CA-IR-260

Ref: HECO-1605 (Rent Expense).

Please provide the following information regarding 2005 forecast of rent case expense:

a. Please update the Company's test year forecast of rent expense, including any additional leased space or revised rental rates.

b. For each listed area, building or suite referenced in the revised HECO-1605, please identify the occupants of the leased square footage by HECO RA (or department).

c. For each listed area, building or suite referenced in the revised HECO-1605, please identify the occupants of the leased square footage by HEI RA (or department).

d. Referring to items (a) and (b) above, please identify the square footage and lease rent attributed to DSM and how such amount is, or will be, reflected in the 2005 test year forecast.

HECO Response:

a. See page 3 for the updated HECO-1605 exhibit. Please note that the ratemaking treatment for the King Street lease has been updated to reflect the new lease currently awaiting PUC approval in Docket No. 05-0084. The ratemaking treatment is consistent with the accounting determination that the new lease will be a capital lease. Since it is a capital lease, HECO will reflect a lease property asset and a lease obligation on its balance sheet. The lease property test year estimate of ~~$9,948,000~~ $10,112,734* (see page 4) will be included in rate base in rebuttal testimony. The lease obligation test year estimate of ~~$10,115,000~~ $10,112,734* (see page 4) will be included in return on rate base in rebuttal testimony. The lease property will be amortized over the lease term, therefore amortization expense will be revised in rebuttal to include a test year estimate of ~~$521,315~~ $192,685* (see p. 4).

b. See page 5 for a listing of the occupants of each rental listed on the revised HECO-1605.

c. See page 5 for a listing of the occupants of the HEI rental.

* SEE FURTHER EXPLANATION OF CHANGES ON PAGE 4 OF 5.

CA-IR-260

Ref: HECO-1605 (Rent Expense).

Please provide the following information regarding 2005 forecast of rent case expense:

a. Please update the Company's test year forecast of rent expense, including any additional leased space or revised rental rates.

b. For each listed area, building or suite referenced in the revised HECO-1605, please identify the occupants of the leased square footage by HECO RA (or department).

c. For each listed area, building or suite referenced in the revised HECO-1605, please identify the occupants of the leased square footage by HEI RA (or department).

d. Referring to items (a) and (b) above, please identify the square footage and lease rent attributed to DSM and how such amount is, or will be, reflected in the 2005 test year forecast.

HECO Response:

a. See page 3 for the updated HECO-1605 exhibit. Please note that the ratemaking treatment for the King Street lease has been updated to reflect the new lease currently awaiting PUC approval in Docket No. 05-0084. The ratemaking treatment is consistent with the accounting determination that the new lease will be a capital lease. Since it is a capital lease, HECO will reflect a lease property asset and a lease obligation on its balance sheet. The lease property test year estimate of $9,948,000 (see page 4) will be included in rate base in rebuttal testimony. The lease obligation test year estimate of $10,115,000 (see page 4) will be included in return on rate base in rebuttal testimony. The lease property will be

[redacted]

Suite 1250/1270. The lease rent attributable to DSM of approximately $91,200 will be included in the 2005 test year estimate as a DSM program expense.

Revised HECO-1605

Hawaiian Electric Company, Inc.
Account 931 - Rent Expense
Test Year 2005 - Rent

	[a]	[b]	[c]	[d]	[a]x[b]x12+ [c]x[d]x12=[e]	[f]	[g]	[h]	[i]	[e]+[f]+[g]+ [h]+[i] x.04167 =[j]	[e]+[f]+[g]+ [h]+[i]+[j] = [k]
EXISTING LEASES	Net sq ft	Monthly Rent per sq ft	Gross sq ft	Monthly CAM(1) per sq ft	Annual Rent (incl CAM)	Annual Real Prop Tax Credit	Op Exp Recon	Misc Exp(4)	After Hour A/C chgs (8)	Annual Gen Excise Tax	Annual Rent TY 2005
											$ in 1000's
Central Pacific Plaza (CPP)											
Suite 700 (2)	7,598	1.35	7,598	0.975	211,984	(16,608)	2,649	144		8,258	206
Suite 1010	3,930	1.43	4,509	0.975	120,194	(9,864)	1,572	144		4,669	117
Suite 1020, 1025 & 1075	3,947	1.44	4,532	0.975	121,229	(9,912)		144		4,645	116
Suite 1201 & 1212 (3)	2,500	1.44	2,871	0.975	16,126	(1,320)	210	30		627	16
Suite 1250 & 1270 (3)	1,464	1.36	1,598	0.975	8,944	(733)		30		343	9
Suite 1300 (2)	9,601	1.35	9,601	0.975	267,868	(20,988)	3,348	144	2,664	10,544	264
Suite 1425	2,404	1.45	2,788	0.975	74,449	(6,096)		144		2,854	71
Suite 1480	1,085	1.43	1,242	0.975	33,150	(2,712)	433	144		1,292	32
Suite 1515	637	1.44	732	0.975	19,572	(1,596)	255	144		766	19
Suite 1520 & 1530 (2)	2,139	1.55	2,451	0.975	68,462	(5,364)	855	144		2,671	67
Suite 1570	2,594	1.43	2,969	0.975	79,250	(6,492)	1,035	144		3,081	77
HEIPC Sublease (5)			1,537	0.975	41,928	(3,360)	536	56		1,632	41
Total - CPP											1,035
King Street (6)	see calculation below										(269)
Honolulu Club		2.45	2,544		74,794					3,117	78
Pacific Tower 8th floor											54
Waiau Viaduct (7)											32
Pauahi Tower											453
											1,383

(1) CAM = Common Area Maintenance

(2) Rents are proposed and awaiting landlord approval.

(3) CPP 12th floor: Lease rent is allocated 21% to O&M and 79% to DSM.

(4) Additional expense per month for miscellaneous key and card charges.

(5) HEIPC Sublease is 39% of HEIPC's total agreement.

(6) King Street rent: (Amortization of lease property will be included in Depreciation and Amortization expense)

GIT on Lease Payments	32,294	see p. 4
less: HEI rent	(301,365)	[4]
Annual rent	(269,071)	

HEI rent:

Total King St. lease payments		807,294	[1]
Total bldg sq ft		58,313	[2]
Monthly Base rent/sq ft		1.15	[1] / [2] / 12
Monthly CAM		1.50	represents the estimated costs of operating expenses per sq. ft.
PSC tax and PUC fees		0.18	(1.15+1.50) x .0682*
		2.83	
HEI sq ft	x	8,874	* .0682 represents the composite PUC Fees and PSC Taxes rate
Monthly HEI rent		25,114	[3]
Annual HEI rent		301,365	[3] x 12 = [4]

(7) Quarterly payment ($7,925 x 4 x .001= $32,000)

(8) Additional expense related to "after-hour" air-conditioning charges (estimate $222 / month)

Note: Numbers may not add exactly due to rounding.

HECO
King Street Capital Lease (Rate making based on lease payments)
Monthly Journal Entries

Monthly discount rate 0.4794%
FV of leased asset 10,209,077

HECO:
Monthly discount rate has changed to .4794% from .4824%. Assumptions have been updated to assume the new lease is executed on July 1, 2005. This resulted in a change in the embedded interest rate calculated due to the change in the value of lease payments over the term of the lease.

	Month Beginning	Monthly Payments A	Excise Tax Payment B	Lease Payment C	Monthly Interest Expense D	Monthly Obligation Reduction E	Ending Lease Obligation F		Monthly Amortization Expense G	Ending Lease Property H	
		B+C	C*1.04167-C	Per Lease	F*Monthly discount rate	C-D	Prior Balance -E		E	Prior Balance -G	
						-	10,209,077	(c)		10,209,077	(a)
1	July 1, 2005	67,275	2,691	64,583	48,945	15,638	10,193,439		15,638	10,193,439	
2	August 1, 2005	67,275	2,691	64,583	48,870	15,713	10,177,726		15,713	10,177,726	
3	September 1, 2005	67,275	2,691	64,583	48,795	15,788	10,161,938		15,788	10,161,938	
4	October 1, 2005	67,275	2,691	64,583	48,719	15,864	10,146,073		15,864	10,146,073	
5	November 1, 2005	67,275	2,691	64,583	48,643	15,940	10,130,133		15,940	10,130,133	
6	December 1, 2005	67,275	2,691	64,583	48,567	16,017	10,114,117		16,017	10,114,117	
7	January 1, 2006	67,275	2,691	64,583	48,490	16,093	10,098,023		16,093	10,098,023	
8	February 1, 2006	67,275	2,691	64,583	48,413	16,170	10,081,853		16,170	10,081,853	
9	March 1, 2006	67,275	2,691	64,583	48,335	16,248	10,065,605		16,248	10,065,605	
10	April 1, 2006	67,275	2,691	64,583	48,257	16,326	10,049,279		16,326	10,049,279	
11	May 1, 2006	67,275	2,691	64,583	48,179	16,404	10,032,875		16,404	10,032,875	
12	June 1, 2006	67,275	2,691	64,583	48,100	16,483	10,016,392	(d)	16,483	10,016,392	(b)
	Total	807,294	32,294	775,000	582,315	192,685			192,685		

HECO:
Interest Expense has changed to $582,315 from $586,010 as a result of the change in the monthly discount rate.

<u>Rate Base Impact</u>:
Lease Property
Beginning of Year (July 1, 2005) 10,209,077 (a)
End of Year (June 30, 2006) 10,016,392 (b)

Test Year Average 10,112,734 [(a)+(b)]/2

HECO:
Amortization has changed to $192,685 from $521,315 as a result in a proposed change to ratemaking treatment based on lease payments as discussed in CA-IR-688.

<u>Return on Rate Base Impact</u>:
Lease Obligation
Beginning of Year (July 1, 2005) 10,209,077 (c)
End of Year (June 30, 2006) 10,016,392 (d)

Test Year Average 10,112,734 [(c)+(d)]/2

HECO:
Obligation reduction has changed to $192,685 from $188,990 as a result of the change in the monthly discount rate.

HECO
King Street Capital Lease
Monthly Journal Entries

Monthly discount rate 0.4824%
FV of leased asset #########

		Monthly Payments A	Excise Tax Payment B	Lease Payment C	Monthly Interest Expense D	Monthly Obligation Reduction E	Ending Lease Obligation F		Monthly Amortization Expense G	Ending Lease Property H	
		B+C	C*1.04167-C	Per Lease	F*Monthly discount rate	C-D	Prior Balance -E		Beginning Lease Property/235 months	Prior Balance -G	
						-	10,209,077	(c)		10,209,077	(a)
1	May 1, 2005	67,275	2,691	64,583	49,248	15,336	10,193,741		43,443	10,165,634	
2	June 1, 2005	67,275	2,691	64,583	49,174	15,410	10,178,332		43,443	10,122,191	
3	July 1, 2005	67,275	2,691	64,583	49,099	15,484	10,162,848		43,443	10,078,748	
4	August 1, 2005	67,275	2,691	64,583	49,025	15,559	10,147,289		43,443	10,035,305	
5	September 1, 2005	67,275	2,691	64,583	48,950	15,634	10,131,655		43,443	9,991,863	
6	October 1, 2005	67,275	2,691	64,583	48,874	15,709	10,115,946		43,443	9,948,420	
7	November 1, 2005	67,275	2,691	64,583	48,798	15,785	10,100,161		43,443	9,904,977	
8	December 1, 2005	67,275	2,691	64,583	48,722	15,861	10,084,300		43,443	9,861,534	
9	January 1, 2006	67,275	2,691	64,583	48,646	15,938	10,068,363		43,443	9,818,091	
10	February 1, 2006	67,275	2,691	64,583	48,569	16,014	10,052,348		43,443	9,774,648	
11	March 1, 2006	67,275	2,691	64,583	48,492	16,092	10,036,257		43,443	9,731,205	
12	April 1, 2006	67,275	2,691	64,583	48,414	16,169	10,020,087	(d)	43,443	9,687,762	(b)
	Total	807,294	32,294	775,000	586,010	188,990			521,315		

Rate Base Impact:
Lease Property

Beginning of Year (May 1, 2005)	10,209,077	(a)
End of Year (April 1, 2006)	9,687,762	(b)
Test Year Average	9,948,420	[(a)+(b)]/2

Return on Rate Base Impact:
Lease Obligation

Beginning of Year (May 1, 2005)	10,209,077	(c)
End of Year (April 1, 2006)	10,020,087	(d)
Test Year Average	10,114,582	[(c)+(d)]/2

Property Location	Occupied by HECO RAs:
Central Pacific Plaza (CPP)	
Suite 700	FA, FD, FI, FB, FC, PW, 6V
Suite 1010/1020/1025/1075	1W, SM, SN, 9S, SR, 4V
Suite 1201/1212/1250/1270	SP, SD, SA
Suite 1300	NC, 9P, NP, KI
Suite 1425	NG
Suite 1480	NL
Suite 1515	PA, PI
Suite 1520 & 1530	PA, PI, NA
Suite 1570	NA, NS, NX
HEIPC Sublease	To be determined
King Street	AA,AC, AD, AT, CA, CB, CD, CP, CS, EM, KB, KC, KF, KM, KT, QC, QE, 9P, 4V, 9V, 8V, PS, 5V, 1V
Honolulu Club	Training/Meeting Rooms
Pacific Tower 8th floor	3V/NI
Waiau Viaduct	Vehicle parking & Storage
Pauahi Tower	EA, EC, ED, EI, EP

	Occupied by HEI RAs:
King Street	9Z, Z4, 4T, 4F, TI, 4C, Z3

CA-IR-261

Ref: HECO-1604, Page 16 (Ellipse Fees).

With regard to the recurring maintenance and BSI fees, please provide the following:

a. Please provide the current or expected term of the contract, including future plans to continue using Ellipse.
b. Please provide support for the 4.166% maintenance fee increase effective June 2004.
c. Please provide a copy of the workpapers and underlying documentation supporting the assumed 2.23% fee increase in 2005.
d. Please explain the timing of the 2005 fee increase for maintenance (June 2005) and BSI (January 2005).
e. Please explain the reference in footnote (c) to the six-year average CPI-urban inflation rate for the period 1997-2002.
f. Please provide a copy of the provisions of the software agreement that address fee escalation.
g. Please provide a copy of a recent 2005 billing, showing current rates and charges.

HECO Response:

a. HECO currently pays annual maintenance fees for Ellipse that covers the months from June to May. Currently, we do not have plans to replace the Ellipse system.
b. The 4.166% multiplier does not represent a maintenance fee increase but rather the Hawaii State General Excise Tax that the service provider passes on and charges HECO.
c. The assumed 2.23% fee increase was derived by averaging the annual Consumer Price Index posted by the U.S. Bureau of Labor Statistics over a six year period from 1997-2002. The CPI for these years were as follows:

1997	1.7	2000	3.4	Average	2.2333
1998	1.6	2001	1.6		
1999	2.7	2002	2.4		

d. Annual maintenance fees for Ellipse cover the period from June to May of the following year, whereas the BSI maintenance fees cover the period from January to December. BSI is a third party software vendor Mincom uses for payroll tax computation and is on a separate maintenance fee schedule.

e. On June 1 of each year, the software license agreement stipulates that the annual maintenance fee shall increase in accordance with the applicable CPI-urban inflation rate posted by the U.S. Bureau of Labor Statistics. A six year average was used due to the fluctuation of this percentage between 1.6% and 3.4% over the past years. See response to item c.

f. Please refer to CA-IR-262 for a copy of the software license agreement.

g. See copies of recent 2005 billings on pages 3-5.

INVOICE

AP RCVD NOV 26 '04 AM 9:42

Mincom

9635 MAROON CIRCLE
SUITE 100
ENGLEWOOD CO 80112
303-446-9000
303-446-8664

HAWAIIAN ELECTRIC COMPANY, INC
ATTN: ACCOUNTS PAYABLE
PO BOX 2750
HONOLULU HI 96840-0001

Cust. No. HWE01
INVOICE I0007383
Date 11/20/04
Ref.

Description	Amount
ELLIPSE: LICENSE FEES LF TERMS: DUE JANUARY 1, 2005 P.O. NO: P63297	
AGREEMENT NO: AA040403	
AMENDMENT NO. 17 TO THE SOFTWARE LICENSE AGREEMENT NO. N099601	
2ND HALF OF THE ELLIPSE SOFTWARE LICENSE FEES DUE JANUARY 1, 2005.	550,000.00
4.166% HAWAII SALES TAX	22,913.00
REMITTANCE ADDRESS: Mincom Inc. Dept. 182 Denver, CO 80271-0182 ACH/EFT WIRE INFORMATION: Wells Fargo Bank Denver, CO ABA#: 121000248 ACCT#: 4159684828	
Total	572,913.00

INVOICE

AP RCVD NOV 22'04 AM11:07

Mincom

9635 MAROON CIRCLE
SUITE 100
ENGLEWOOD CO 80112
303-446-9000
303-446-8664

HAWAIIAN ELECTRIC COMPANY, INC
ATTN: ACCOUNTS PAYABLE
PO BOX 2750
HONOLULU HI 96840-0001

Cust. No. HWE01
INVOICE I0007376
Date 11/18/04
Ref.

Description	Amount
ELLIPSE: MAINTENANCE FEES MF TERMS: DUE JANUARY 1, 2005 P.O. NO: ~~P63297~~ P71154	
AMENDMENT NO. 8 & 9 TO THE SOFTWARE LICENSE AGREEMENT NO. NA099601	
ANNUAL MAINTENANCE FEES ON BSI REPORT FACTORY FOR THE PERIOD 01/01/05-12/31/05.	7,522.51
ANNUAL MAINTENANCE FEES FOR BSI TAX FACTORY FOR THE PERIOD 01/01/05-12/31/05.	6,798.40
4.166% HAWAII SALES TAX	597.86
THIS INVOICE HAS BEEN ADJUSTED FOR A 1.9% INCREASE IN THE CONSUMER PRICE INDEX.	
REMITTANCE ADDRESS: Mincom Inc. Dept. 182 Denver, CO 80271-0182	
	Total

INVOICE

Mincom

9635 MAROON CIRCLE
SUITE 100
ENGLEWOOD CO 80112
303-446-9000
303-446-8664

HAWAIIAN ELECTRIC COMPANY, INC
ATTN: ACCOUNTS PAYABLE
PO BOX 2750
HONOLULU HI 96840-0001

Cust. No. HWE01

INVOICE I0007376

Date 11/18/04

Ref.

Description	Amount
ACH/EFT WIRE INFORMATION: Wells Fargo Bank Denver, CO ABA#: 121000248 ACCT#: 4159684828	
	Total
	14,918.77

CA-IR-262

<u>Ref: HECO T-16, Pages 14-15 (Ellipse Fees)</u>.

Please provide a copy of Amendment 17 to the Software License Agreement No. NA099601, concerning the $1.1 million fee.

<u>HECO Response:</u>

Amendment 17 to the Software License Agreement No. NA099601 contains confidential and proprietary information that may be useful to other software licensees in negotiating their licensing agreements with the software licensor. HECO will provide a copy of the Amendment 17 under a protective order, once a protective order is issued in this proceeding.

Ref: HECO-1604, Page 16 (Ellipse Fees).

The monthly amortization was determined by dividing the $1.1 million fee by 24 months and multiplying by 1.04166. Please provide the following information:

a. Why is the fee increased by 4.166%?

b. Please provide a copy of any payback or cost/benefit studies prepared by, or for, the Company in deciding to pay the $1.1 million fee.

c. Please provide the recurring monthly fees prior to the software maintenance fee reduction, effective June 2004.

HECO Response:

a. The 4.166% represents the Hawaii State General Excise Tax that the service provider passes on and charges HECO.

b. See pages 2-3 to this response.

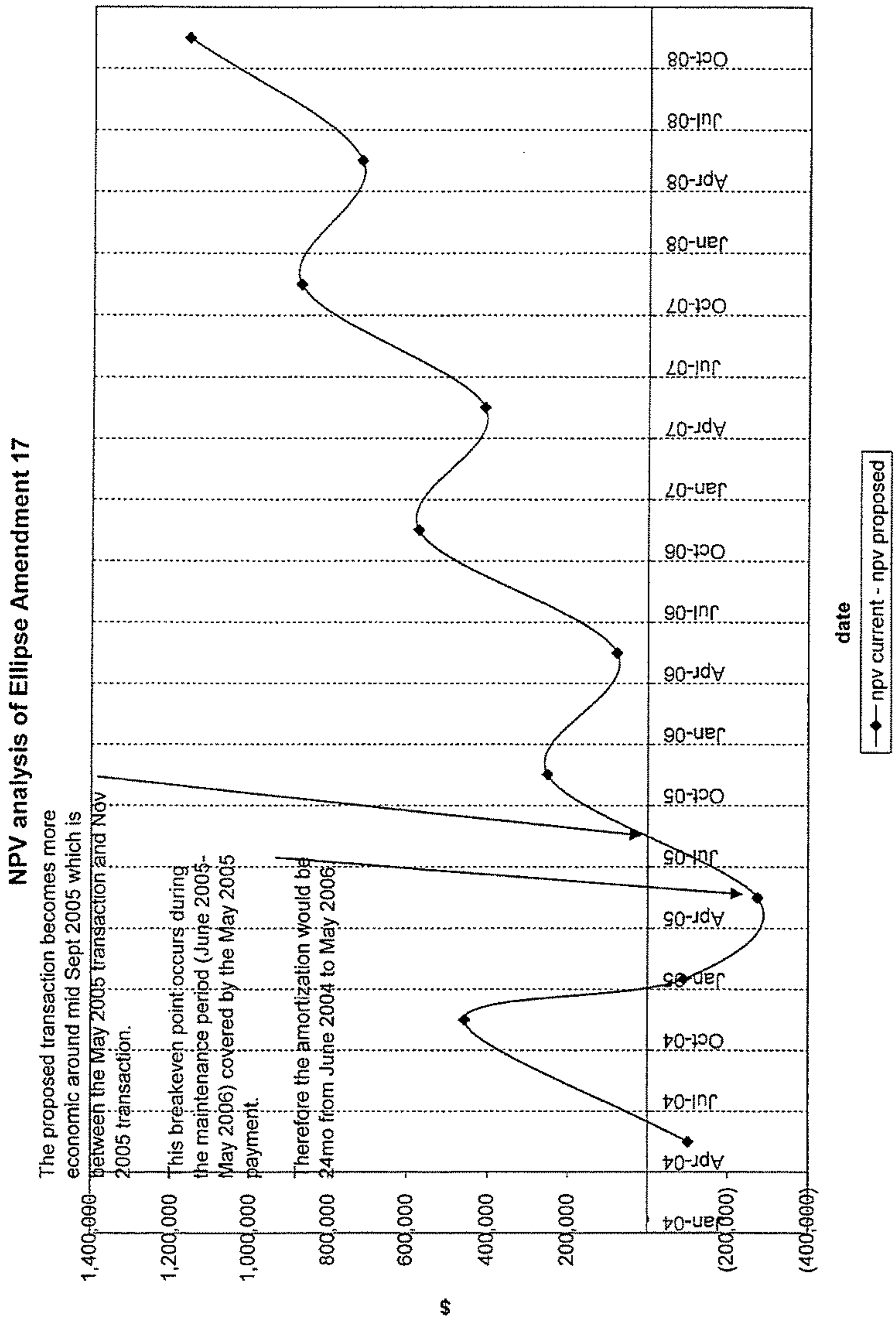
c. Prior to the software maintenance fee reduction effective June 2004, the monthly amortization of HECO's portion of the software maintenance fees was $33,972 in 2004.

<u>Cash Flow Analysis of Relicensing Proposal</u>

NOTE: excludes BSI and GET taxes because they are equal under both scenarios.

2.23% CPI
8.42% Long Term Forecast Weighted After Tax Cost of Capital

Trx Date	Covered Period	Current	Covered Period	Proposed	NPV Current	NPV Proposed	Diff
[redacted]							
1/1/05		-		550,000	875,074	965,198	(90,124)
5/31/05		-	6/05 - 5/06	191,170	875,074	1,148,815	(273,741)
11/30/05	CY2006	569,580		-	1,400,420	1,148,815	251,605
5/31/06		-	6/06 - 5/07	195,433	1,400,420	1,321,949	78,471
11/30/06	CY2007	582,282			[illegible]	[illegible]	[illegible]


NPV analysis of Ellipse Amendment 17
The proposed transaction becomes more economic around mid Sept 2005 which is between the May 2005 transaction and Nov 2005 transaction.
This breakeven point occurs during the maintenance period (June 2005-May 2006) covered by the May 2005 payment.
Therefore the amortization would be 24mo from June 2004 to May 2006.
1,400,000
1,200,000
1,000,000
800,000
600,000
400,000
200,000
(200,000)
(400,000)
$
Jan-04
Apr-04
Jul-04
Oct-04
Jan-05
Apr-05
Jul-05
Oct-05
Jan-06
Apr-06
Jul-06
Oct-06
Jan-07
Apr-07
Jul-07
Oct-07
Jan-08
Apr-08
Jul-08
Oct-08
date
npv current - npv proposed

CA-IR-264

Ref: HECO T-2, Page 20 and 21 and Appendix H, Pages 15 to 17 of the February 2004 voluminous workpapers.

In prior rate cases, the Consumer Advocate was able to replicate the econometric equation used by HECO to determine the test year forecast. For the instant proceeding, however, the Consumer Advocate was not able to replicate the econometric equation using EVIEWS4. Please provide the following information.

a. Please provide the data file used to determine HECO's model.

b. Please provide information from the software package (MetrixND) which describes the method used to calculate the AR Models.

c. Please provide the results of the residential use model without the AR(1) specification.

HECO Response:

The Consumer Advocate ("CA") provided the results produced by EVIEWS4 using HECO's data (see page 3 of this response). As shown on page 4 of this response, HECO was able to replicate the CA's results on MetrixND 4.0 by reducing the original observation period by one year (i.e., using 1977 thru 2002 data instead of 1976 thru 2002 data). The MetrixND results for this specification are provided electronically in a file named *CA-IR-264 FORECASTUSE EXPORT AR 77-02.XLS* on a CD labeled CA-IR-264 under separate transmittal. Due to the price lag and the AR(1) in the equation, EVIEWS4 uses only 25 data observations whereas MetrixND uses the full 26 observations available (after the price lag) in the time series. This one year difference appears to be the reason why the CA has been unable to replicate HECO's results using EVIEWS4.

a. The data used to determine HECO's model, along with the model statistics, is being provided electronically in a file called *CA-IR-264 FORECASTUSE EXPORT AR 76-02 RC.XLS* on a CD labeled CA-IR-264 under separate transmittal.

b. The information on the method used by MetrixND for autoregressive models is provided on pages 5 - 7 of this response. The information was obtained from the MetrixND 4.0 User Guide and includes additional information provided by Itron, the software vendor.

c. As requested, HECO ran the model without the autoregressive ("AR") function over the period 1976 thru 2002 using MetrixND. The results are shown on page 8 of this response and the data files and statistics are provided electronically on a CD labeled CA-IR-264 in a file called *CA-IR-264 FORECASTUSE EXPORT NO AR 76-02.XLS* under separate transmittal.

It should be noted that the results without the AR(1) are essentially the same as HECO's original results shown on page H17 of the January 25, 2005 voluminous workpapers, and shown again on page 9 of this response. The estimated coefficients from a model with serially correlated errors are inefficient, but unbiased. Correcting for serial correlation should not change the estimated coefficients in theory, but in actuality, the coefficients will usually change. The fact that the coefficients shown on pages 8 and 9 of this response are very close supports the stability of the model. On the other hand, a comparison of the models using the 1977 – 2002 data with (see page 4 of this response) and without AR(1) (see page 10 of this response) shows that the coefficients are very different, and may indicate a problem with the 1977 – 2002 model.

Dependent Variable: USEPERCUST
Method: Least Squares
Date: 01/24/05 Time: 14:08
Sample(adjusted): 1978 2002
Included observations: 25 after adjusting endpoints
Convergence achieved after 11 iterations

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	7375.529	280.6365	26.28144	0.0000
TOTALACACT	2939.015	712.4178	4.125409	0.0005
REALPRICE(-1)	-4983.442	1343.706	-3.708729	0.0013
AR(1)	0.726627	0.093231	7.793854	0.0000

R-squared	0.912937	Mean dependent var	7558.549
Adjusted R-squared	0.900500	S.D. dependent var	315.6758
S.E. of regression	99.57574	Akaike info criterion	12.18536
Sum squared resid	208221.9	Schwarz criterion	12.38038
Log likelihood	-148.3170	F-statistic	73.40175
Durbin-Watson stat	2.326752	Prob(F-statistic)	0.000000

Inverted AR Roots	.73

Project:	**S:\EnergyServices\MKTFCST\heco04irp\econometrics\model\residential sales anr**
Model:	**ForecastUse**
Dependent Variable:	**Annunally.usePERcust**
Date:	**February 23, 2005**
Time:	**08:18 AM**
Estimation Begin Date:	**1977:1**
Estimation End Date:	**2002:1**
Forecast Period End Date:	**2002:1**

Variable	**Coefficient**	**StdErr**	**T-Stat**	**P-Value**
CONST	7375.697	280.647	26.281	0%
Annunally.TotalACact	2938.562	712.439	4.125	0%
Trans1.lagprice	-4983.588	1343.843	-3.708	0%
AR(1)	0.727	0.093	7.792	0%

Regression Statistics		**Forecast Statistics**	
Iterations	10	Forecast Observations	0
Adjusted Observations	25	Mean Abs. Dev. (MAD)	0.00
Deg. of Freedom for Error	21	Mean Abs. % Err. (MAPE)	0.00%
R-Squared	0.913	Avg. Forecast Error	0.00
Adjusted R-Squared	0.900	Mean % Error	0.00%
Durbin-Watson Statistic	2.327	Root Mean-Square Error	0.000
Durbin-H Statistic	0.000	Theil's Inequality Coefficient	0.000
AIC	9.348	-- Bias Proportion	0.00%
BIC	9.543	-- Variance Proportion	0.00%
F-Statistic	73.383	-- Covariance Proportion	0.00%
Prob (F-Statistic)	0.000		
Log-Likelihood	-142.39		
Model Sum of Squares	2183360		
Sum of Squared Errors	208270		
Mean Squared Error	9917.60		
Std. Error of Regression	99.59		
Mean Abs. Dev. (MAD)	64.81		
Mean Abs. % Err. (MAPE)	0.86%		
Ljung-Box Statistic	5.33		
Prob (Ljung-Box)	0.377		

Variable	**Coefficient**	**Mean**	**Elast**
Annunally.TotalACact	2938.562	0.244	0.095
Trans1.lagprice	-4983.588	0.126	-0.083

Regression Model with Seasonal ARMA Errors

The linear least squares (regression) model is a special case of this more general nonlinear framework. The user specifies the variables to be included in the model and optionally the order of the AR and MA processes for the error term. The specification list is as follows:

- Dependent variable (y),
- Independent variables (x's),
- Order (P) of autoregressive (AR) terms for the error process,
- Order (Q) of moving average (MA) terms for the error process,
- Order (SP) of seasonal autoregressive (SAR) terms, and
- Order (SQ) for seasonal moving average (SMA) terms.

In addition to these variables and parameters, the user must specify whether to include a constant term, whether to include weights in the estimation process, whether to mark off bad spots in the databases, whether to mark off observations to be used to calculate forecast test statistics, the limits of the estimation period, and the limits of the forecast period.

Specification

The specification has two parts. The first covers the linear model and its residual (μ). The second describes the process that generates the residuals of the linear model. This process includes AR terms in μ as well as MA terms in the IID time series residual, ε.

These components have the following general form.

$$y_t = a + bx_t + u_t \qquad \textbf{\textit{(R-1)}}$$

where

$$\left(1-\sum_{i=1}^{P}\phi_i L^i\right)\left(1-\sum_{m=1}^{SP}\Phi_m L^{m\times s}\right)\times u_t = \left(1+\sum_{j=1}^{Q}\theta_j L^j\right)\left(1+\sum_{n=1}^{SQ}\Theta_n L^{n\times s}\right)\times \varepsilon_t$$

where P, SP, Q, and SQ are the integers giving the order of the AR and MA processes, and where s is the number of periods per year.

Through substitution and rearrangement, the model equation (R-1) can be rewritten to specify y as a function of x, lagged y values, lagged x values, and current and lagged values of the time series residual, ε, as follows:

$$y_t = a + bx_t + \sum_{i=1}^{P} \phi_i \left(y_{t-i} - a - bx_{t-i}\right) + \sum_{m=1}^{SP} \Phi_m \left(y_{t-m\times s} - a - bx_{t-m\times s}\right)$$
$$- \sum_{i=1}^{P} \sum_{m=1}^{SP} \phi_i \Phi_m \left(y_{t-i-m\times s} - a - bx_{t-i-m\times s}\right)$$
$$+ \varepsilon_t + \sum_{j=1}^{Q} \theta_j \varepsilon_{t-j} + \sum_{n=1}^{SQ} \Theta_j \varepsilon_{t-n\times s} + \sum_{j=1}^{Q} \sum_{n=1}^{SQ} \theta_j \Theta_n \varepsilon_{t-j-n\times s}$$

(R-2)

With minor rearrangement, the current value of the time-series residual can be written as follows.

$$\varepsilon_t = y_t - a - bx_t - \sum_{i=1}^{P} \phi_i \left(y_{t-i} - a - bx_{t-i}\right) - \sum_{m=1}^{SP} \Phi_m \left(y_{t-m\times s} - a - bx_{t-m\times s}\right)$$
$$+ \sum_{i=1}^{P} \sum_{m=1}^{SP} \phi_i \Phi_m \left(y_{t-i-m\times s} - a - bx_{t-i-m\times s}\right)$$
$$- \sum_{j=1}^{Q} \theta_j \varepsilon_{t-j} - \sum_{n=1}^{SQ} \Theta_n \varepsilon_{t-n\times s} - \sum_{j=1}^{Q} \sum_{n=1}^{SQ} \theta_j \Theta_n \varepsilon_{t-j-n\times s}$$

(R-3)

Once the model has been specified, the purpose of estimation is to find the parameters (a, b, ϕ, Φ, θ, and Θ) that make the residuals in (R-3) small. The specification for the error term can be identified by estimating a linear regression without ARMA errors, and analyzing the autocorrelations and partial autocorrelations for the estimated residuals.

The following illustrates the estimation process for a Regression model with an AR(1) process. Let the structural model be written as:

$y_t = a + bx_t + u_t$ (E1)

and the error process follows an AR(1) process which can be written as:

$u_t = \rho u_{t-1} + \omega_t$ (E2)

We can then write the equation that is estimated as follows:

$y_t = a + bx_t + \rho y_{t-1} - \rho a - \rho b X_{t-1} + \varepsilon_t$ (E3)

Since the parameters interact we need to use nonlinear least squares to estimate the model. The particular algorithm we use is based on Levenburg-Marquardt. The steps in the algorithm are:

1. Use least squares to estimate the original structural equation (E1) without ARMA errors. The parameters from this step will form the starting values for the structural model parameters, a & b.
2. Use the residuals from Step 1 to construct a regression of current residuals regressed on lagged residuals. The parameter from this step will form the starting value for the AR coefficient. Since we need to lag the residuals one period we will ultimately lose one observation from the estimation dataset.
3. Using these initial parameter values computes the sum of squared residuals from the complete equation (E3). Record the sum of squared errors.
4. Compute the Gradient. *MetrixND* uses analytical derivatives to compute the Gradient. Other packages, like EVIEWS, uses numerical derivatives.
5. Update the model parameters as follows:

$$B_{J+1} = B_J + Gradient \times StepSize$$

Here, B represents the vector of model parameters. Essentially at each step we take the previous parameter values and add to or subtract from to get to the next set of parameter values. How much we add to or subtract from is determined by the second part of the equation. The Gradient determines the direction that will improve the objective function the best. The StepSize determines how far along the Gradient you move. You continue with steps 4 and 5 until you come to a local minimum (i.e. the Gradient is close to 0).

Source: *MetrixND 4.0 Users Guide* and conversations with Itron consultant (software vendor).

Project:	**S:\EnergyServices\MKTFCST\heco04irp\econometrics\model\residential sales anr**
Model:	**ForecastUse**
Dependent Variable:	**Annunally.usePERcust**
Date:	**February 10, 2005**
Time:	**08:51 AM**
Estimation Begin Date:	**1976:1**
Estimation End Date:	**2002:1**
Forecast Period End Date:	**2002:1**

Variable	**Coefficient**	**StdErr**	**T-Stat**	**P-Value**
CONST	8138.763	296.446	27.454	0%
Annunally.TotalACact	1370.885	573.934	2.389	3%
Trans1.lagprice	-7132.895	1720.941	-4.145	0%

Regression Statistics	
Iterations	1
Adjusted Observations	26
Deg. of Freedom for Error	23
R-Squared	0.587
Adjusted R-Squared	0.551
Durbin-Watson Statistic	0.340
Durbin-H Statistic	0.000
AIC	10.862
BIC	11.007
F-Statistic	16.334
Prob (F-Statistic)	0.000
Log-Likelihood	-175.10
Model Sum of Squares	1529023
Sum of Squared Errors	1076487
Mean Squared Error	46803.79
Std. Error of Regression	216.34
Mean Abs. Dev. (MAD)	170.96
Mean Abs. % Err. (MAPE)	2.25%
Ljung-Box Statistic	26.74
Prob (Ljung-Box)	0.000

Forecast Statistics	
Forecast Observations	0
Mean Abs. Dev. (MAD)	0.00
Mean Abs. % Err. (MAPE)	0.00%
Avg. Forecast Error	0.00
Mean % Error	0.00%
Root Mean-Square Error	0.000
Theil's Inequality Coefficient	0.000
-- Bias Proportion	0.00%
-- Variance Proportion	0.00%
-- Covariance Proportion	0.00%

Variable	**Coefficient**	**Mean**	**Elast**
Annunally.TotalACact	1370.885	0.244	0.044
Trans1.lagprice	-7132.895	0.126	-0.118

Project:	**S:\EnergyServices\MKTFCST\heco04irp\econometrics\model\residential sales anr**
Model:	**ForecastUse**
Dependent Variable:	**Annunally.usePERcust**
Date:	**February 22, 2005**
Time:	**01:55 PM**
Estimation Begin Date:	**1976:1**
Estimation End Date:	**2002:1**
Forecast Period End Date:	**2002:1**

Variable	**Coefficient**	**StdErr**	**T-Stat**	**P-Value**
CONST	8163.691	376.927	21.659	0%
Annunally.TotalACact	1374.545	996.912	1.379	18%
Trans1.lagprice	-7166.465	1884.012	-3.804	0%
AR(1)	0.723	0.158	4.588	0%

Regression Statistics	
Iterations	2
Adjusted Observations	26
Deg. of Freedom for Error	22
R-Squared	0.798
Adjusted R-Squared	0.771
Durbin-Watson Statistic	1.675
Durbin-H Statistic	0.000
AIC	10.223
BIC	10.417
F-Statistic	28.981
Prob (F-Statistic)	0.000
Log-Likelihood	-165.79
Model Sum of Squares	2079349
Sum of Squared Errors	526161
Mean Squared Error	23916.41
Std. Error of Regression	154.65
Mean Abs. Dev. (MAD)	101.02
Mean Abs. % Err. (MAPE)	1.32%
Ljung-Box Statistic	1.74
Prob (Ljung-Box)	0.884

Forecast Statistics	
Forecast Observations	0
Mean Abs. Dev. (MAD)	0.00
Mean Abs. % Err. (MAPE)	0.00%
Avg. Forecast Error	0.00
Mean % Error	0.00%
Root Mean-Square Error	0.000
Theil's Inequality Coefficient	0.000
-- Bias Proportion	0.00%
-- Variance Proportion	0.00%
-- Covariance Proportion	0.00%

Variable	**Coefficient**	**Mean**	**Elast**
Annunally.TotalACact	1374.545	0.241	0.044
Trans1.lagprice	-7166.465	0.126	-0.119

Project:	**S:\EnergyServices\MKTFCST\heco04irp\econometrics\model\residential sales anr**
Model:	**ForecastUse**
Dependent Variable:	**Annunally.usePERcust**
Date:	**February 23, 2005**
Time:	**09:08 AM**
Estimation Begin Date:	**1977:1**
Estimation End Date:	**2002:1**
Forecast Period End Date:	**2002:1**

Variable	**Coefficient**	**StdErr**	**T-Stat**	**P-Value**
CONST	8138.763	296.446	27.454	0%
Annunally.TotalACact	1370.885	573.934	2.389	3%
Trans1.lagprice	-7132.895	1720.941	-4.145	0%

Regression Statistics	
Iterations	1
Adjusted Observations	26
Deg. of Freedom for Error	23
R-Squared	0.587
Adjusted R-Squared	0.551
Durbin-Watson Statistic	0.340
Durbin-H Statistic	0.000
AIC	10.862
BIC	11.007
F-Statistic	16.334
Prob (F-Statistic)	0.000
Log-Likelihood	-175.10
Model Sum of Squares	1529023
Sum of Squared Errors	1076487
Mean Squared Error	46803.79
Std. Error of Regression	216.34
Mean Abs. Dev. (MAD)	170.96
Mean Abs. % Err. (MAPE)	2.25%
Ljung-Box Statistic	26.74
Prob (Ljung-Box)	0.000

Forecast Statistics	
Forecast Observations	0
Mean Abs. Dev. (MAD)	0.00
Mean Abs. % Err. (MAPE)	0.00%
Avg. Forecast Error	0.00
Mean % Error	0.00%
Root Mean-Square Error	0.000
Theil's Inequality Coefficient	0.000
-- Bias Proportion	0.00%
-- Variance Proportion	0.00%
-- Covariance Proportion	0.00%

Variable	**Coefficient**	**Mean**	**Elast**
Annunally.TotalACact	1370.885	0.244	0.044
Trans1.lagprice	-7132.895	0.126	-0.118

CA-IR-265

Ref: HECO WP-201, page 39 and February 2004 voluminous forecast, Appendix G.

Please identify the specific 3rd Party CHP installations expected in 2004 and 2005 and the kw and kwh impacts for each project.

HECO Response:

HECO WP-201, page 39, is consistent with the 3rd party CHP forecast for Oahu shown on page 1, Exhibit A in HECO's application for approval of a CHP Program and Schedule CHP tariff in Docket No. 03-0366, filed with the Commission in October 2003. At the time this forecast was prepared, the forecasted 3rd party CHP installations for 2004 and 2005 were generic estimates, and not based on any specific customer. HECO's general methodology for developing the CHP forecast was described on Page 22 of HECO T-1 in Docket No. 03-0371. HECO's updated CHP forecast of March 2005 estimates third-party CHP installations in 2004 and 2005 as follows:

	Project	Capacity (kW)	Energy (kWh)
2004	3rd Party CHP	0	0 (no 3rd party CHP in 2004)
2005	3rd Party CHP	300	1,206,000 (partial year with installation in July '05)

Regarding actual 3rd party CHP projects, HECO uses the Rule 14 interconnection agreement applications as its primary method to track 3rd party distributed generation customers, including potential 3rd party CHP installations. One 3rd party 300kW SNG-fueled CHP system was planned for installation in 2004, however HECO understands that the installation is still in progress with completion now estimated in July 2005. Additionally, a 140kW propane-fired CHP system was planned by the City & County of Honolulu for installation in either late 2004 or early 2005 at the City & County's Kapolei Hale building, however the project has been cancelled. HECO is not aware of any other specific 3rd party CHP projects being planned for the 2005 timeframe. This information is reflected in the most recent HECO CHP forecast update of March 2005. Please see the response to CA-IR-276 for discussion of this update.

CA-IR-266

Ref: HECO Response to CA-IR-18.

Please explain the rationale for continuation of the Rule No. 4 Service Contracts provision for use of a "FORM CONTRACT FOR CUSTOMER RETENTION" and related "STANDARD FORM CONTRACT FOR CUSTOMER RETENTION," given the Company's interests in expanded DSM to constrain load growth and reduce the need for future capacity additions. Please provide reference to any HECO testimony associated with retaining customer retention contracting provisions and provide copies of any studies and other available information associated with your response.

HECO Response:

HECO is NOT proposing to continue the Rule 4 Standard Form Contract for Customer Retention. As stated in HECO T-22, page 51, lines 15-22, HECO is proposing to discontinue the Rule 4 Standard Form Customer Retention Rates in light of HECO's current increasing need for new generation capacity and/or measures to mitigate customer load growth.

CA-IR-267

Ref: HECO Response to CA-IR-18.

a. Please explain whether the Company is proposing any changes to the Rule No. 4 Service Contracts "ATTACHMENT 4 ENERGY AUDIT SPECIFICATIONS" details.

b. If yes, please provide reference to any HECO testimony associated with any proposed changes and/or provide copies of any studies and other available information associated with your response.

HECO Response:

a. Please see HECO Response to CA-IR-266. HECO is proposing to discontinue the Rule 4 Standard Form Contract for Customer Retention.

b. Please see HECO Response to subpart a. above.

CA-IR-268

<u>Ref: HECO T-1, page 19, line 23.</u>

According to Mr. Alm, "Even if the Company has not incurred expenses at the same levels in prior years, if the expenses are reasonable they should be included for ratemaking purposes during the period when the rates are in effect." Please respond to the following:

a. State with specificity <u>each</u> of the objective criteria or tests that were applied by HECO to determine if the expenses that have been included in the 2005 test year projections are "reasonable."

b. Explain whether judgment is required by employees preparing the test year expense projections, to determine if expense levels being proposed are "reasonable."

managing and supervising the activities in the various process areas, who explain in detail the reasons for the expenses, and the bases for the expense levels.

b. Judgment may be required by employees as they prepare their budget, and therefore the test year expense projections, and in determining if expense estimates being proposed are "reasonable." For example, judgment may be used when determining whether to use historical costs or a specific proposal for a similar type of cost item as the basis for developing the budget amount.

c. The 2005 budget that was used as the basis for the test year amounts was initially prepared in 2003 and reviewed in conjunction with the 2004 budget. In 2004, that budget was again reviewed, primarily by the various O&M expense witnesses. After reviewing the budget from a NARUC account perspective (vs. department perspective in 2003), the O&M expense witnesses participated in meetings with management with the objective of reviewing the budget, including trends in data such as staffing levels, so that issues and adjustments could be identified, and the level of expenses that is reasonable from an overall perspective would be determined.

CA-IR-269

<u>Ref: HECO T-1, page 19, line 10.</u>

Mr. Alm explains the actions taken by HECO since September 11, 2001 and states "HECO deliberately reduced spending, while not compromising reliability, during that period. However, such reduction in the level of spending and unfilled positions can not continue for an indefinite period of time. After a while, the vacancies need to be filled or certain work will not get done." Please provide the following information:

a. Identify and describe the specific elements of HECO's reduced spending policies, including details regarding any hiring suspensions, budget reductions, deferred programs or projects, capital investment deferrals, etc.

b. Provide copies of memoranda, budget guidelines, intercompany correspondence and other documents that were distributed by management to explain the measures identified in your response to subpart (a) of this information request.

c. List and, to the extent possible, quantify the amounts of any work that did not get done during the past few years as a result of the actions taken.

d. Explain whether HECO believes that the Commission should expect the Company to maintain any continuing budget austerity plans, ongoing hiring constraints or any other spending limitations in an effort to promote operational efficiency and minimize the burden of rate increases upon customers.

<u>HECO Response:</u>

a. See response to CA-IR-12.

b. See response to CA-IR-12.

c. To the extent available, the information requested may be found in the testimony of the various O&M Expense witnesses and in responses to the following IRs: CA-IR-1, CA-IR-2, CA-IR-20, CA-IR-21, CA-IR-59, CA-IR-67, CA-IR-77, and CA-IR-175.

d. As the Company is mindful of producing and delivering a reliable supply of electricity when and where our customers need it, in a safe manner, and at reasonable prices, the Company continually strives to achieve improvements in efficiency and productivity and reflects them in our budgeted work force requirements and non-labor costs. As such, the Company does not believe that the Commission should expect the Company to maintain any continuing budget austerity plans, ongoing hiring constraints or any other spending limitations in an effort to promote operational efficiency and minimize the burden of rate increases upon customers. The Company, however, may institute budget austerity plans, hiring constraints, and other spending limitation in times of economic uncertainty, while not compromising reliability and safety, and in an effort to maintain financial integrity.

(REVISED 5-6-05)

CA-IR-270

<u>Ref: HECO T-1, page 8.</u>

The Question at line 12 addresses the principle factors affecting the need for HECO to increase its rates. The response focuses on several resource procurement issues.

a. Is minimizing rate impacts one of the criteria used by HECO for resource selection?

   1. If so, please specify all of the other criterion considered, and explain how each criterion is applied in determining which resources to procure.

   2. If not, please explain why not.

b. Please identify the actual system average rate charged to customers and the average rate for each customer class (<u>i.e.</u>, residential, commercial, industrial) for each year beginning from the year 2000 through 2004.

c. Please provide the projected system average and class rates during the period 2005 through 2010 assuming HECO's proposed resource acquisitions are approved.

d. Please identify each resource procurement alternative considered by HECO in lieu of the proposed new and expanded DSM programs.

e. Please provide the projected system average and class rates during the period 2005 through 2010 under each of the resource procurement alternatives identified in response to subpart (d) above.

<u>HECO Response:</u>

a. There are a number of factors that are considered in acquiring resources, one of which is rate impacts. The most explicit statements of resource acquisition objectives for supply-side and demand-side resources are in the Commission's integrated resource planning ("IRP") framework, and in the integrated resource plans ("IRP Plans") filed by HECO pursuant to the IRP Framework. See, for example, Paragraphs III.A, III.B.4, III.B.5 and IV.B. of "A Framework for Integrated Resource Planning", approved by Decision and Order No. 11630, issued May 22, 1992, in Docket No. 6617; Chapter 5 of HECO's Integrated Resource Plan

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1998-2017, filed January 30, 1998 in Docket No. 95-0347.

Planning objectives sometimes compete or conflict with one another. For example, the objective of minimizing environmental impacts may conflict with the objective of minimizing utility costs, because more environmentally benign resources may cost more than conventional resources. As a result, integrated resource planning ("IRP") requires the evaluation of resources or resource strategies that involve trade-offs because of the conflicting objectives. Thus, the IRP Framework, for example, provides that the "utility shall develop a number of alternative plans, each representing optimization from a <u>different</u> perspective ...", and that the utility shall rank the various [alternative plans] based on such criterion as it may establish with the advice of its advisory groups. The utility shall designate one of these plans as its preferred plan ... ." Framework ¶¶IV.I.2, 4 (pp. 23-24) (emphasis added). If the sole objective was to minimize rates, then the sole perspective considered would be the utility cost perspective.

The factors and objectives considered in adding other types of resources are addressed in the specific applications requesting approval for such resource acquisitions. <u>See</u>, <u>e.g.</u>, applications filed (1) December 18, 2003 in Docket No. 03-0417 (East Oahu Transmission Project), (2) October 2, 2003 in Docket No. 03-0360 (New Dispatch Center Project), (3) November 6, 2001 in Docket No. 01-0444 (Waiau Fuel Oil Pipeline Project), and (4) August 26, 2004 in Docket No. 04-0268 (Customer Information System Project).

Note also that <u>minimizing</u> rates may not always be the objective. For example, the acquisition of demand-side resources may result in somewhat higher utility rates, while reducing total resource costs and customer bills.

b. The actual system average rate and the average rate for each customer class including

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residential, commercial, and industrial, for 2000 to 2004 is provided on page 4 to this response.

c. The projected system average and class rates for test-year 2005 is also provided on page 4 of this response. The requested rates for 2006 to 2010 are not available.

d. Please refer to HECO's response to CA-IR-273.

e. The requested projected system average and class rates for 2005 through 2010 under each resource procurement alternatives are not available.

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HAWAIIAN ELECTRIC COMPANY, INC.
RECORDED AVERAGE RATES BY CUSTOMER CLASS

	Recorded Average Rates, ¢/kWh[1]			
YEAR	Residential	Commercial Customers[2]	Industrial Customers[3]	Total System
2000	14.477	12.772	10.396	12.211
2001	14.255	12.682	10.353	12.125
2002	13.859	12.206	9.918	11.713
2003	14.888	13.245	10.972	12.772
2004	15.690	14.019	11.795	13.583
TY 2005[4]	16.274	14.481	11.917	13.922

[1] Based on the classes' total recorded revenues and recorded sales.
[2] Includes Schedules G, J, and H.
[3] Includes Schedules PS, PP, and PT.
[4] Average rates at proposed rates, Docket No. 04-0113.

CA-IR-270

<u>Ref: HECO T-1, page 8.</u>

The Question at line 12 addresses the principle factors affecting the need for HECO to increase its rates. The response focuses on several resource procurement issues.

a. Is minimizing rate impacts one of the criteria used by HECO for resource selection?

   1. If so, please specify all of the other criterion considered, and explain how each criterion is applied in determining which resources to procure.

   2. If not, please explain why not.

b. Please identify the actual system average rate charged to customers and the average rate for each customer class (<u>i.e.</u>, residential, commercial, industrial) for each year beginning from the year 2000 through 2004.

c. Please provide the projected syste [illegible]

c. The projected system average and class rates for test-year 2005 is also provided on page 3 of this response. The requested rates for 2006 to 2010 are not available.

d. Please refer to HECO's response to CA-IR-273.

e. The requested projected system average and class rates for 2005 through 2010 under each resource procurement alternatives are not available.

HAWAIIAN ELECTRIC COMPANY, INC.
RECORDED AVERAGE RATES BY CUSTOMER CLASS

YEAR	Recorded Average Rates, ¢/kWh[1]			
	[illegible]esidential	Commercial Customers[2]	Industrial Customers[3]	Total System
2000	14.477	12.772	10.396	12.211
2001	[illegible]255	12.682	10.353	12.125
2002	13.8[illegible]	12.206	9.918	11.713
2003	14.888	13.245	10.972	12.772
2004	15.690	14.019	11.795	13.583
TY 2005[4]	16.274	[illegible]4.481	11.917	13.922

[1] Based on the classes' total recorded revenues and recorded sales.
[2] Includes Schedules G, J, and H.
[3] Includes Schedules PS, PP, and PT [illegible]

CA-IR-271

Ref: HECO T-1, at 10.

Regarding HECO's "4.5 years per day reliability guideline used for capacity planning." Please provide the following information.

a. Identify the actual LOLP for each year beginning from the year 2000 through 2004.

b. Provide the projected LOLPs for each year during the period 2005 through 2010 absent further resource additions.

c. Identify an upper bound on the LOLP that the Company would view as reasonable in 2004 and beyond.

HECO Response:

a. For a complete discussion of LOLP calculations, please refer to HECO's response to CA-IR-38, in Docket No. 04-0320, Kalaeloa PPA Amendment Nos. 5 and 6 filed on February 23, 2005.

It should be noted that HECO uses a convention where generating system reliability is the inverse of LOLP. Therefore, an LOLP of 0.1 days per year (or more commonly expressed as one day in 10 years) is equivalent to a generating system reliability of 10 days per year. HECO uses this convention because larger values indicate greater generating system reliability. Please refer to page 9 in HECO's response to CA-IR-38, in Docket No. 04-0320.

HECO does not normally perform retrospective reliability calculations as its focus is on identifying potential generating system reliability issues in future years. HECO has performed "backcast" generating system reliability calculations only for the years 2000 and 2001. In these calculations for historical years, the generating system reliability values were determined for each year using recorded hourly system demand, actual maintenance outages, and recorded Equivalent Forced Outage Rates for each generating unit. The results are shown below:

Year	Calculated Generating System Reliability (Years per Day)
2000	21.3
2001	19.2

b. HECO has estimated generating system reliability for the years 2005 to 2009 for a base scenario. HECO's estimate, as well as the assumptions used to develop the estimate and estimates of generating system reliability for alternative scenarios (lower peak reduction benefits from energy efficiency DSM, load management DSM and CHP and higher Equivalent Forced Outage Rate), has been provided in HECO's Adequacy of Supply report, which was filed with the Commissionon on March 10, 2005.

c. HECO does not have an LOLP value that it would consider a reasonable upper bound in 2004 and beyond. Rather, in addition to LOLP, HECO considers it ability to meet its capacity planning rules related to the loss of the largest unit and ability to maintain an adequate amount of spinning reserve for quick load pickup. HECO is performing an analysis of its ability to meet these criteria. The results have been provided in HECO's Adequacy of Supply report, which was filed with the Commission on March 10, 2005.

CA-IR-272

Ref: HECO T-1, at 10-11.

Please provide the Company's current estimate of when generating system reliability will fall below the 4.5 years per day reliability guideline threshold (a) absent further resource additions, and (b) assuming the proposed demand and supply side resources are approved and deliver the expected capacity benefits.

HECO Response:

Please refer to HECO's response to CA-IR-271, part b.

CA-IR-273

<u>Ref: HECO T-1, at 11.</u>

What is the Company's current expectation regarding whether and when the "40 MW or more of additional firm capacity ... can be implemented."

a. Please describe the likelihood and expected in-service dates of additional capacity from the "two amendments to HECO's power purchase agreement with Kalaeloa Partners, L.P."

b. Please provide a schedule that shows the expected in-service dates and quantities for the "additional firm capacity" (as that term is used in line 9) derived from "load reduction measures."

<u>HECO Response:</u>

Please refer to HECO's response to CA-IR-6, in Docket No. 04-0320 (Kalaeloa PPA Amendment Nos. 5 and 6), filed on February 23, 2005, for information on the capacity and energy resources HECO is pursuing. HECO has prepared updated projections for the acquisition of the peak reduction benefits of energy efficiency DSM, load management DSM and CHP. The updated projections were provided in HECO's Adequacy of Supply report, which was filed with the Commission on March 10, 2005.

a. The upgrades to Kalaeloa's combustion turbines that enable the facility to achieve a higher output are already completed. Therefore, the additional capacity is already available, although the results from recent tests need to be evaluated to establish the actual rating of the facility for contract purposes. The timing of when HECO can utilize the capacity and energy that would be made contractually available under Amendment Nos. 5 and 6 to the HECO-Kalaeloa PPA will depend upon Commission approval of these Amendments in Docket No. 04-0320.

b. Please refer to the response preceding part a above.

CA-IR-274

Ref: HECO T-1, at 11.

HECO states that its ability to defer construction of a new generation resource will depend on whether other new demand and supply side projects are approved and completed.

a. Please state whether the deferral of the new generation unit also depends on the continued operation of all existing generating units at their existing capacities through the end of the decade.

b. Please indicate whether the Company is aware of any specific plans or proposals from within the Company, or from government leaders, to [illegible]

[illegible]

2009

[redacted]

Posted on: Sunday, November 14, 2004

Power plant move explored

By Andrew Gomes
Advertiser Staff Writer

Sandwiched between the blue-green waters of Honolulu Harbor and sleek downtown high-rises, the Leslie A. Hicks Power Plant near Aloha Tower has been called both an eyesore and essential.

Several previous ideas to remove the downtown plant, including two by HECO, were considered in the late '80s and early '90s in response to the state's invitation to redevelop land surrounding Aloha Tower. But none was realized.

The latest attempt is a linchpin in an ambitious $300 million plan by Hughes to create a residential community with loft-style condominiums at Piers 5 and 6 tied to a downtown streetcar system.

The 3.5-acre power plant site would become a park connected to an improved Irwin Park as a kind of central business district front lawn that Hughes describes as a "crowning urban amenity."

Hughes' overall redevelopment plan, which would share revenues and expenses with the state, i determined, then approved by the state Consumer Advocate and Public Utilities Commission.

The cost of building a new plant is not included in Hughes' $300 million estimate for the greater redevelopment project. The greater plan budgets $30 million for demolishing the power plant and cleaning the site, which may qualify for federal funding. Park construction is budgeted at $22 million, which includes removing the parking lot from Irwin Park. A land swap could avoid property acquisition costs.

Hughes' timetable calls for a 2005 demolition of the power plant's 'ewa wing, which houses a maintenance shop, environmental staff offices and decommissioned generation units.

The diamondhead building with the operating generators would be taken down in 2008, with a replacement plant in operation, according to the development timetable. "Nothing seems to be (unachievable) at all," Hughes said.

But there appears to be little public demand for a park at the site.

"Why should you build another park that will cost us more money?" asked downtown office worker Sheila Pagaduan. "Hello-o? We need to fix the roads and put more money into the schools."

Pagaduan, however, does agree that the windowless complex with black-tipped exhaust stacks, oil tanks and high-voltage warning signs appears out of place next to Aloha Tower Marketplace, the Hawai'i Maritime Museum, cruise ships and other visitor-oriented attractions.

"It would definitely be more scenic not to have it there," said Massachusetts resident Cheryl Korytoski, a first-time visitor to Hawai'i.

Korytoski's husband, David, who was sitting outside the Maritime Museum last week, could hear the plant's whirring. "It's sort of noisy," he said. "You definitely hear the generators."

Not everyone knows that the complex at 170 Ala Moana named after a former HECO president is a power plant, including some kama'aina who work downtown and guessed that the facility was a factory, a warehouse and a water filtration plant.

"It looks like a sewage treatment plant," said Gene Dominguez, a downtown denizen who has a birds-eye view of the plant from his office.

Like his colleague Pagaduan, Dominguez doesn't favor replacing the plant with a park. He suggested painting the buildings and tanks creatively to resemble an aquarium or some other aesthetic attraction.

Still, many people agree that the power plant needs to go. They cite security concerns with having a potential terrorist target at the foot of Honolulu's business district, pollution and blight.

HECO at one time was among those in favor of retiring the plant, which dates to 1894 and was replaced with the existing generation units in 1954 and 1957.

In 1989, a HECO subsidiary partnered with local developer Jack Myers to bid on the state redevelopment opportunity to remake 17 acres of state land around Aloha Tower.

The $1.1 billion proposal by HECO and Myers, which used the power plant site, was to develop three condo towers, three office towers, a hotel and an 80-meter-high whirling column of water spouting from the harbor.

The HECO/Myers bid, one of four competing proposals, wasn't selected. But in 1990, the team announced it would redevelop the power plant site alone. The plan was for a condo or hotel or a combination tower possibly with offices.

HECO won approval from the Consumer Advocate to sell the power plant site to the partnership for $32.7 million, which would have generated a $36 rebate for a typical residential power customer because there was no plan to replace the plant.

At the time, HECO had lighter demand for power, plus plans to obtain additional power from independent producers.

However, in 1993, after the state's economy had started its slide into a decade of stagnation, HECO aborted the project and withdrew its pending application from the Public Utilities Commission.

HECO spokeswoman Lynne Unemori said the declining real estate market and the ability to continue operating the downtown plant efficiently were behind the decision. "The economics just didn't pan out anymore," she said.

Since then, HECO has been able to upgrade the plant and extend its expected useful life to 2024 and possibly longer.

"In general, it is much more cost-effective to modernize an existing unit and keep it operating than to retire the unit and replace the capacity with a new generating unit," HECO said in a 1998 regulatory filing, noting that it would cost $17.4 million in 1997 dollars to modernize the downtown plant compared with $64 million to build a new one.

Fuel is not much of an economic factor, according to HECO, which said said any new power plant would likely burn more expensive but more efficient and cleaner-burning fuel, compared with the cheaper, higher polluting but less efficient fuel used in the downtown plant.

Hughes said that even though it takes less effort to keep the status quo, it is not civically responsible to do so. "The removal of this plant from the waterfront is in the best long- and short-term interest of Honolulu," he said.

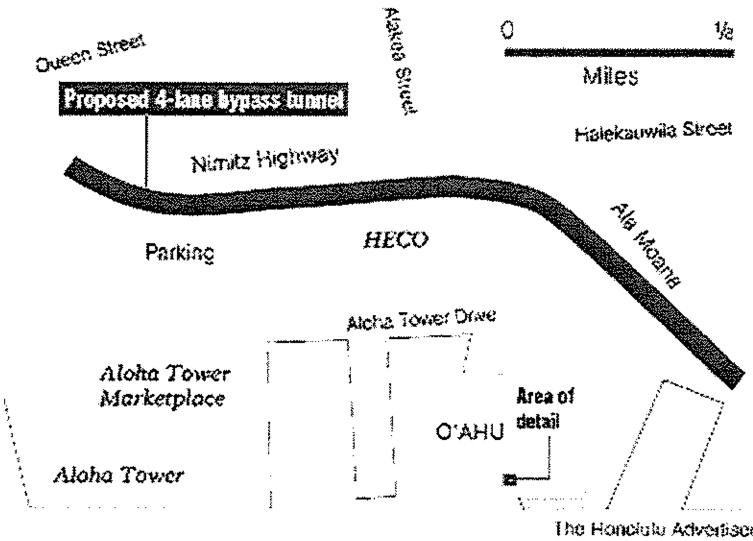
HECO is agreeable to replacing the downtown plant, and is sharing information with the state. But it will be largely up to the development authority and the Gov. Linda Lingle administration to find a viable solution for the utility, the state, the developer and the public.

"It is a very exhaustive process, but it can be done," Orodenker said.

Reach Andrew Gomes at agomes@honoluluadvertiser.com or 525-8065

Posted on: Saturday, June 19, 2004

Aloha Tower proposal reshaped



By Andrew Gomes
Advertiser Staff Writer

A Dallas developer planning a roughly $300 million remake of state property around Aloha Tower wants to sell condominiums above what may be ceded lands and build a downtown bypass tunnel under Nimitz Highway to make the project more feasible.

Developer UC Urban wants to create a traffic tunnel under Nimitz Highway as part of the Aloha Tower redevelopment. The company also now wants to sell condos on what is suspected to be ceded lands.

Rebecca Breyer • The Honolulu Advertiser

Ken Hughes of UC Urban also proposed sharing costs and profits with the state, and rebuilding the Pier 10 cruise ship terminal as part of project revisions presented yesterday to the state Aloha Tower Development Corp. board.

The changes create new hurdles for the ambitious plan, which the state agency has pursued with Hughes since requesting proposals in late 2002 and choosing to work with the experienced developer in February 2003.

Honolulu Harbor connected with a downtown streetcar system and ferry terminal.

The project, called Pacific Quay, has evolved over the last year with the addition of the 2-mile streetcar system, elimination of hotel and office high-rises, and an increase in the number of residential lofts to 550 from 250.

Other elements in the plan include 1,400 parking spaces, removing the parking lot from Irwin Park and constructing a larger park on the site of Hawaiian Electric Co.'s power plant, which would have to be relocated and is viewed as the project's biggest potential "fatal flaw."

Despite the obstacles, Hughes and agency board members

raised more questions and challenges, there sti ll was optimism that Hughes can succeed where others have failed in redeveloping the area.

"Everything that Ken has presented is accomplishable," said agency acting executive director Dan Orodenker.

Said Hughes: "I'm very comfortable. We're ready to push this thing to completion."

Among the several new twists Hughes shared, the most critical related to the project's residential component.

Previously, Hughes planned to lease the land at Piers 5 and 6, and build the rental loft apartments. Yesterday he said a some agency board members questioned the conclusion.

Office of Hawaiian Affairs information officer Manu Boyd said he needed to do more research to find whether OHA considers Piers 5 and 6 ceded land, but said in general that

state harbors, ports and submerged lands are ceded.

Orodenker said the agency has asked the Department of Land & Natural Resources for a determination but has not received a response.

Stubenberg floated a possible option he described as a "lollipop condo" where four floors of parking and maybe

some retail on Piers 5 and 6 would be owned by the state. Condos on higher floors would be sold fee simple and fairly new corporate structures not addressed in agency rules that allow partnering with private companies.

To finance the project, Hughes is asking the state to issue $146 million in general obligation bonds as an investment in public benefits of the project. The balance would be financed through private debt and other sources.

Hughes estimates that the project would create about 3,000 jobs and would generate $600 million in economic benefits for the state over a 10-year period.

The state has already spent $210,000 and expects to spend another $83,000 as its share of less than half of project study costs under an agreement with Hughes that expires at the end of next month.

The next goal for Hughes is to sign a memorandum of understanding with the state and Hawaiian Electric agreeing to cooperate. "It's just a cooperative effort to see what's possible, recognizing that the state has a need to redevelop the waterfront area and Hawaiian Electric has a need to keep the lights on," he said.

Assuming the power plant agreement is reached, Hughes said he will negotiate a formal development partnership with the state, start lobbying the legislature in mid-August and with hope be able to sell bonds by March 2004.

If all goes well, construction could begin in about two years at the earliest and take two years to complete, though the park could take up to six years because of the need to relocate the power plant.

CA-IR-275

Ref: HECO T-1, at 11.

Regarding the list of factors that might affect the need for the next central station generating unit, please provide a projection, for each year through 2009, of:

a. the expected load reduction benefits (MWs) from "already-installed" load management and energy efficiency DSM programs;

b. the expected load reduction benefits (MWs) from "yet-to-be-installed" load management and energy efficiency DSM programs;

c. the expected capacity benefits (MWs) from distributed generation;

d. the expected capacity benefits (MWs) from renewable generation installed pursuant to Act

e. the capacity additions (MWs) that are expected to result from generating unit additions;

f. the capacity additions (MWs) that are expected to result from generating unit upgrades;

g. the "40 MW or more of additional firm capacity" that is expected to be provided through load reduction measures;

h. the expected level of capacity reductions (MWs) attributable to generating unit retirements;

i. the expected level of the capacity reductions (MWs) attributable to generating unit de-ratings; and

1996.

b. Please refer to HECO's response to CA-IR-273.

c. Please refer to HECO's response to CA-IR-273

d. Please refer to HECO's responses to CA-IR-6, pages 4 and 5, and CA-IR-40, both in Docket No. 04-0320 (Kalaeloa PPA Amendment Nos. 5 and 6), filed on February 23, 2005.

e. The generating unit targeted for installation in 2009 will be in the range of 75 MW to 120 MW, depending upon which unit is selected from among combustion turbine vendor proposals.

f. No additional capacity is expected from upgrades to HECO's existing generating units. Please refer to HECO's response to CA-IR-6, page 4, in Docket No. 04-0320 (Kalaeloa PPA Amendment Nos. 5 and 6) filed on February 23, 2005 and HECO's Adequacy of Supply Report filed on March 10, 2005.

g. Please refer to HECO's response to CA-IR-273.

h. No generating units are scheduled for retirement. Please also refer to HECO's response to CA-IR-274.

i. There are no plans to derate existing generating units. Please also refer to HECO's response to CA-IR-274.

j. Please also refer to HECO's response to CA-IR-271, part b.

CA-IR-276

Ref: HECO T-1, at 11.

Regarding the discussion of CHP installations:

a. Is increasing the quantity of CHP on HECO's system one of the Company's resource procurement goals?

b. If so, please specify the goal in terms of the amount of CHP that HECO wants to have installed on its system.

c. Please identify the actual CHP on HECO's system (MW and MWH) for each year beginning from the year 2000 through 2004.

d. What is the expected increase in CHP levels (MW and MWH) in each year during the period from 2005 through 2010?

HECO Response:

a. HECO, HELCO and MECO, herein collectively referred to as the "Companies", see a customer demand and at the same time a broader role for CHP in its overall electric system, based on the potential system benefits of DG. The reasons for, and the benefits of, utility participation in the provision of CHP systems are detailed in the Companies' CHP Application in Docket No. 03-0366, filed on October 23, 2003:

1) The provision of CHP services by utilities is a natural step in the evolution of electric utility services, and electric utility customers should have the option of acquiring CHP systems from Hawaii utilities.

2) The installation of cost-effective, energy-efficient CHP systems should further the objectives of Hawaii's State energy policy and assist the Companies in meeting their utility Renewable Portfolio Standards.

3) Development of the CHP market may generate enough capacity to help defer the need for

new central station generation.

4) CHP systems strategically located and reliably operated may potentially defer the need for transmission and distribution system upgrades.

5) The utilities' provision of CHP systems on a regulated basis will ensure that the interests of all customers are taken into consideration. Benefits should be available to the

projects or non-utility CHP projects. An updated CHP forecast was developed in early February 2005 that reflected these events, however, subsequent to this forecast the Pacific Allied CHP Agreement was terminated by the customer. A revised forecast which takes the Pacific Allied termination into account is shown on page 5. This March 2005 forecast serves as the basis for HECO's CHP capacity assumptions in the 2005 HECO Adequacy of Supply filing.

All prospective CHP projects are subject to customer desire and support, which can be extremely variable. A CHP system under development by the City and County of Honolulu for their Kapolei Hale facility was cancelled in January 2005 by the City, evidence that CHP projects are subject to changes in customer sentiment.

Site specific factors also add uncertainty, as they may affect the feasibility of moving forward on a project even when the desire for CHP is strong. As an example, the largest potential HECO CHP project that was included in the June 2004 IRP-3 CHP forecast, the Outrigger Beachwalk CHP project, has been deferred indefinitely by the mutual agreement of HECO and Outrigger. Another potential HECO CHP project, the Ko Olina Vacation Club project, has been deferred indefinitely due to the infeasibility of the initial site designated by the customer.

In addition, utility CHP projects are faced with schedule uncertainty especially in the current timeframe while the Commission considers distributed generation policy issues in Docket No. 03-0371. Such uncertainty can affect customer support for a utility CHP project, as was the case with Pacific Allied Products, which terminated its planned CHP project with HECO in mid-February 2005. No utility-owned CHP systems were installed in 2004, and no utility-owned CHP systems are planned for installation in 2005.

Conversely, short term CHP forecasts may also move in the positive direction unexpectedly, mostly when major new facility developments are proposed. As an example, the recent announcement of major development in the Ko Olina area, including several hotels and an aquarium, presents significant additional CHP potential for Oahu that was not previously accounted for in the forecasts.

[redacted]

HECO CHP Forecast - With Utility Participation
Total Market Annual Potential
(Updated March, 2005)

	Total kW [1]	Systems	Utility Systems	Utility kW	3rd Party Systems	3rd Party kW
2005	300	1	0	0	1	300
2006	4900	7	6	4400	1	500
2007	4500	6	5	4000	1	500
2008	5300	7	6	4800	1	500
2009	5300	7	6	4800	1	500
2010	3700	5	4	3200	1	500
2011	2900	4	3	2400	1	500
2012	2900	4	3	2400	1	500
2013	2100	3	2	1600	1	500
2014	2100	3	2	1600	1	500
2015	2100	3	2	1600	1	500
2016	2100	3	2	1600	1	500
2017	1300	2	1	800	1	500
2018	1300	2	1	800	1	500
2019	1300	2	1	800	1	500
2020	1300	2	1	800	1	500
2021	1300	2	1	800	1	500
2022	1300	2	1	800	1	500
2023	1300	2	1	800	1	500
2024	1300	2	1	800	1	500
2025	1300	2	1	800	1	500
Total	49900	71	50	39600	21	10300
2005-10	24000	33	27	21200	6	2800

[1] Includes utility and 3rd party
CHP
Source: HECO Energy Projects 3/9/05

CA-IR-277

Ref: HECO T-1, at 10-11.

Regarding the discussion of the Company's need for capacity, please:

a. Please provide basic information regarding the annual capacity and energy requirements of HECO's system (i.e., before the resource additions proposed in the instant rate case). Please provide data and charts (in MWs and MWhs) that depict the following:

   1. The current and projected peak load and energy requirements of the system.

   2. The current and projected contributions from existing supply-side resources.

   3. The current and projected contributions from existing demand-side resources

   4. The projected contributions from proposed new or uprated supply-side resources.

   5. The projected contributions from proposed new and expanded demand-side resources.

   6. The projected resource (capacity and energy) needs.

b. Please provide a reasonable "high" need scenario, based on consideration of the factors outlined in the response to subpart (a) above.

c. Please provide a reasonable "low" need scenario, based on consideration of the factors outlined in the response to subpart (a), above.

HECO Response:

a. For response to parts 1 to 6, please see Attachment 1 on page 2 to this response.

b. Please see Attachment 2 on page 3 to this response.

c. Please see Attachment 3 on page 4 to this response.

CA-IR-277 Attachment 1

Projected Peak Load and Energy Requirements for HECO System

Net MW	Base Peak No Future DSM/LM/CHP [1]	Future DSM/LM [2]	Future CHP (Utility/Non-Utility) [3]	Base Peak Reduced by Future DSM/ LM/CHP [4] = [1] - [2] - [3]	Difference in Peak due to Future DSM/LM/CHP [5] = [1] - [4]
2005	1325	18	0	1307	18
2006	1376	38	5	1333	43
2007	1407	56	10	1341	66
2008	1421	73	15	1333	88
2009	1449	84	20	1345	104

Notes:

[1] Forecasted peak reduced by acquired DSM only and not reduced by future DSM, LM, utility and non-utility CHP.
[2] Forecasted DSM and LM impacts.
[3] Forecasted CHP impacts for both utility and non-utility.
[4] Forecasted peak also reduced by future DSM, LM ...

MWH	Base Energies No Future DSM/CHP [6]	Future DSM [7]	Future CHP (Utility/Non-Utility) [8]	Base Energies Reduced by Future DSM/CHP [9] = [6] - [7] - [8]	Difference in Peak due to Future DSM/CHP [10] = [6] - [9]
2005	7,889,600	46,800	0	7,842,800	46,800
2006	8,199,700	81,862	16,579	8,101,259	98,441
2007	8,381,500	130,485	57,271	8,193,744	187,756
2008	8,508,300	179,124	91,059	8,238,117	270,183
2009	8,629,000	227,746	126,625	8,274,629	354,371

Notes:

CA-IR-277 Attachment 2

Projected Peak Load and Energy Requirements for HECO System for "High" Scenario

Net MW	Base Peak No Future DSM/LM/CHP [1]	Future DSM/LM [2]	Future CHP (Utility/Non-Utility) [3]	Base Peak Reduced by Future DSM/ LM/CHP [4] = [1] - [2] - [3]	Difference in Peak due to Future DSM/LM/CHP [5] = [1] - [4]
2005	1387	18	0	1369	18
2006	1438	38	5	1395	43
2007	1477	56	10	1411	66
2008	1508	73	15	1420	88
2009	1535	84	20	1431	104

Notes:

[1] Forecasted peak reduced by acquired DSM only and not reduced by future DSM, LM, utility and non-utility CHP.
[2] Forecasted DSM and LM impacts.
[3] Forecasted CHP impacts for both utility and non-utility.
[4] Forecasted peak also reduced by future DSM, LM, utility and non-utility CHP.
[5] Forecasted DSM, LM, and CHP (utility and non-utility) impacts.

MWH	Base Energies No Future DSM/CHP [6]	Future DSM [7]	Future CHP (Utility/Non-Utility) [8]	Base Energies Reduced by Future DSM/CHP [9] = [6] - [7] - [8]	Difference in Peak due to Future DSM/CHP [10] = [6] - [9]
2005	8,234,800	46,800	0	7,842,800	392,000
2006	8,529,100	81,862	16,579	8,430,659	98,441
2007	8,755,900	130,485	57,271	8,568,144	187,756
2008	8,932,900	179,124	91,059	8,662,717	270,183
2009	9,099,400	227,746	126,625	8,745,029	354,371

Notes:

[6] Forecasted energy sales reduced by acquired DSM only and not reduced by future DSM, utility and non-utility CHP.
[7] Forecasted DSM impacts.
[8] Forecasted CHP impacts for both utility and non-utility.
[9] Forecasted peak also reduced by future DSM, utility and non-utility CHP.
[10] Forecasted DSM and CHP (utility and non-utility) impacts.

CA-IR-277 Attachment 3

Projected Peak Load and Energy Requirements for HECO System for "Low" Scenario

Net MW	Base Peak No Future DSM/LM/CHP [1]	Future DSM/LM [2]	Future CHP (Utility/Non-Utility) [3]	Base Peak Reduced by Future DSM/ LM/CHP [4] = [1] - [2] - [3]	Difference in Peak due to Future DSM/LM/CHP [5] = [1] - [4]
2005	1295	18	0	1277	18
2006	1316	38	5	1273	43
2007	1334	56	10	1268	66
2008	1356	73	15	1268	88
2009	1376	84	20	1272	104

Notes:
[1] Forecasted peak reduced by acquired DSM only and not reduced by future DSM, LM, utility and non-utility CHP.
[2] Forecasted DSM and LM impacts.
[3] Forecasted CHP impacts for both utility and non-utility.
[4] Forecasted peak also reduced by future DSM, LM, utility and non-utility CHP.
[5] Forecasted DSM, LM, and CHP (utility and non-utility) impacts.

MWH	Base Energies No Future DSM/CHP [6]	Future DSM [7]	Future CHP (Utility/Non-Utility) [8]	Base Energies Reduced by Future DSM/CHP [9] = [6] - [7] - [8]	Difference in Peak due to Future DSM/CHP [10] = [6] - [9]
2005	7,716,600	46,800	0	7,842,800	-126,200
2006	7,832,700	81,862	16,579	7,734,259	98,441
2007	7,949,300	130,485	57,271	7,761,544	187,756
2008	8,089,700	179,124	91,059	7,819,517	270,183
2009	8,211,900	227,746	126,625	7,857,529	354,371

Notes:
[6] Forecasted energy sales reduced by acquired DSM only and not reduced by future DSM, utility and non-utility CHP.
[7] Forecasted DSM impacts.
[8] Forecasted CHP impacts for both utility and non-utility.
[9] Forecasted peak also reduced by future DSM, utility and non-utility CHP.
[10] Forecasted DSM and CHP (utility and non-utility) impacts.

CA-IR-278

<u>Ref: HECO T-1, at 10-11.</u>

Regarding the discussion of the Company's need for capacity, please:

a. provide a current projection, for each year through 2009, of the need for additional capacity resources (in MWs);

b. identify the date on which that projection was developed; and

c. provide a copy of all workpapers, reports and other materials used to develop that projection.

<u>HECO Response:</u>

a. Please see HECO's response to CA-IR-271, parts b and c.

b. Please see HECO's response to CA-IR-271, parts b and c.

c. Please see HECO's response to CA-IR-271, parts b and c.

CA-IR-279

Ref: HECO T-1, at 12.

Regarding the Question (line 24) discussing the Company's resource needs if load grows faster than forecast, please:

a. State whether the Company has performed any analyses of the contingencies (including higher or lower rates of load growth, etc.) that might affect its need for capacity resources.

b. If yes:

   1. please provide copies of any such contingency analyses (i.e., that are not out-of-date, or otherwise in need of updating); and

   2. provide a copy of all workpapers, reports and other materials used to develop the contingency analyses provided in response to subpart (b) above.

HECO Response:

a. Please see HECO's response to CA-IR-271, parts b and c.

b. Please see HECO's response to CA-IR-271, parts b and c.

CA-IR-280

Ref: HECO T-1, at 12.

Regarding the response to the question "What will be needed if load grows faster than forecast?" and other potential contingency scenarios:

a. Is increasing resilience under sensitivity analysis one of the criteria used by the Company for resource procurement purposes?

b. If so, please describe the criterion and explain how it is applied.

c. Please identify the factors that might affect the cost of HECO's resource portfolio.

d. Please describe the degree to which HECO's portfolio is currently hedged against adverse movement by the various factors described in the response to subpart (c) above.

e. Does the Company have a risk mitigation strategy?

f. If so, please describe it. For example, please identify any upper and lower bounds on hedging various risk factors that the Company would view as reasonable in 2005 and beyond.

HECO Response:

a. In the IRP process, HECO does test various candidate plans under certain sensitivities. In the context of IRP, a plan is considered "resilient" if it compares favorably to other plans under various sensitivities.

b. In the HECO IRP-3 integration process, candidate long-term resource plans are tested under various sensitivities. For example, in the current IRP analyses, six candidate plans were evaluated under the following scenarios (1) lower energy efficiency DSM penetration; (2) no future energy efficiency DSM after 2005 and a smaller CHP market; (3) high fuel price forecast; (4) higher fuel price forecast based on the Integration Technical Committee's forecast; (5) high sales and peak forecast; (6) Honolulu Power Plant retirement scenario; and (7) alternative combustion turbine sizes. These results of these sensitivity analyses were presented to the HECO IRP-3 Advisory Group on November 15, 2004. Under each of these sensitivities, consideration is given to (i) changes in the ranking of the candidate plans according to Total Resource Costs in the Planning Period (20 years) and Study Period (20-year Planning Period plus 30 years of end-effects) and to Societal Costs (Total Resource Costs plus monetized externality costs); (ii) changes in timing of the need for additional resources; and (3) changes in the composition of the plans to more optimally meet Renewable Portfolio Standards.

c. Factors that may affect the cost of HECO's long-term resource plans, which contain a portfolio of resources, include, but are not limited to, costs to implement energy efficiency and load management DSM programs, rate of customer acceptance of energy efficiency and load management DSM programs, capital costs of supply-side resources, operations and maintenance costs (labor and non-labor) for existing and new supply-side resources, projected fuel prices, laws or regulations that may be enacted and which are relevant to the electric utility industry, new technologies, rate of demand growth, electricity consumption patterns of consumers, the cost of purchased power, and transmission costs.

d. HECO's current resource plan contains a broad array of energy resources, including energy efficiency DSM, load management DSM, CHP, existing firm capacity from oil-fired, coal-fired and waste-to-energy generating plants, planned new firm generating capacity and the potential for renewable energy. (Please see HECO response to CA-IR-6, pages 4 and 5, in Docket No. 04-0320 (Kalaeloa Amendment Nos. 5 and 6), filed on February 23, 2005, for information on the potential renewable energy options. Please also refer to HECO's Adequacy of Supply report, filed with the Commission on March 10, 2005, for additional information on the resources HECO is pursuing.) Depending upon the cost-effectiveness of each resource, the proportions of each resources energy contribution may be changed to some extent to mitigate cost increases which may arise from some of the cost factors identified in part c. For example, if oil prices continue to rise, a coal unit rather than an oil-fired unit may be more cost-effective in the future to provide firm capacity. Depending on the level of oil prices, renewable technologies may become more cost-effective and a greater proportion of energy may be generated from renewable resources.

e. HECO is unclear as to what risks are being referred to. Risks can come in the form of lower than expected energy efficiency and load management DSM penetration, lower than expected customer acceptance of CHP, lower than expected availabilities of generating units, higher than expected costs for conventional or renewable energy resources, higher or lower than expected demand, higher or lower than expected fuel prices, unforeseeable catastrophic events, changes in laws and regulations, or in other forms. For practical purposes, HECO must limit the number of scenarios it can consider in the IRP integration process. Please refer to the response to part b. above for a description of the sensitivity analyses performed to evaluate certain risks.

f. Please refer to HECO's response to part e.

CA-IR-281

a. Is maintaining an appropriate mix of baseload, cycling and peaking generating capacity a goal of the Company's resource procurement process?

b. Please identify the actual generation mix for each year beginning with the year 2000 through 2004.

c. What is the projected generation mix in each year during the period 2005 through 2010 with and without the resource additions proposed in the instant rate case?

d. Please identify the target generation mix.

HECO Response:

a. Yes. The appropriate mix of baseload, cycling and peaking generating capacity will depend on the daily and seasonal pattern of total system demand, the cost of providing each type of capacity, and contractual power purchase obligations (firm and as-available).

b. Please see the table below for the existing and projected mix of firm generating capacity.

	Net MW			Percentage		
	Baseload	**Cycling**	**Peaking**	**Baseload**	**Cycling**	**Peaking**
2000	1,203	310	102	74%	19%	6%
2001	1,203	310	102	74%	19%	6%
2002	1,203	310	102	74%	19%	6%
2003	1,203	310	102	74%	19%	6%
2004	1,203	310	102	74%	19%	6%
2005	1,232	310	102	75%	19%	6%
2006	1,232	310	102	75%	19%	6%
2007	1,232	310	102	75%	19%	6%
2008	1,232	310	102	75%	19%	6%
2009	1,232	310	202	71%	18%	12%
2010	1,232	310	202	71%	18%	12%

The baseload capacity includes 406 MW from firm capacity Independent Power Producers. It is assumed that the firm capacity added in 2009 is from a 100 MW (nominal) peaking combustion turbine. The actual capacity of the generating unit will depend on which unit is selected from among three vendors in a competitive bidding process.

c. See response to part b. above.

d. HECO does not have a target mix of baseload, cycling and peaking generating capacity.

Please see the response to part a. above.

CA-IR-282

a. Is fuel diversity one of the criteria used by HECO for resource procurement?

b. If so, please specify the criterion and explain how it is applied in determining which resources to procure.

c. Please rate the diversity of the existing fuel supply mix.

d. Please identify the trend. That is, to what degree is fuel flexibility becoming an increasing problem? By what measure?

e. Please identify a fuel diversity target.

HECO Response:

a. Fuel diversity is a consideration in the IRP process in the development of long-term resource plan and in the selection of the utility's preferred plan.

b. In HECO's IRP-3 process, seven broad categories of long-term resource plan objectives were established. These seven categories included (in no particular order) Protect the Environment, Economical Electricity, Power Quality and Reliability, Energy Security and Sustainable Future, Minimize Potential Negative Societal and Cultural Impacts, Increase Plan Flexibility and Utility Financial Integrity and Competitiveness. Under each category, several attributes were identified and the attributes were quantified to the extent possible to serve as "measures of success" in meeting the broad objectives. The objectives and attributes were developed with HECO IRP Advisory Group input.

Fuel Diversity was considered under the category of Energy Security and Sustainable Future. The attributes under this category included (a) ability to utilize different types of fuels, (b) CHP penetration (demand and energy), (c) system fuel efficiency (d) DSM penetration (demand and energy), (e) energy produced by commercially available indigenous and renewable resources (wind, photovoltaic, biomass and municipal solid waste), (f) Renewable Portfolio Percentage, and (g) fuel consumption (oil) and fuel consumption (coal). These attributes were quantified as a means to "measure" fuel diversity for each of the six candidate plans developed with Advisory Group input. These six plans included (Plan 1) Least Cost Plan, (Plan 2) Meets the State RPS Law – Oahu Only, (Plan 3) Maximize Renewable Energy, (Plan 4) Meets the State RPS Law (HECO, HELCO, MECO consolidated), (Plan 5) Maximize Fuel Diversity, and (Plan 6) Combination Plan. Plan 5 was developed specifically to maximize fuel diversity by incorporating wind and coal-fired generation and high levels of energy efficiency DSM, load management DSM and CHP.

In each of the six plans, the measures for each attribute were quantified to the extent possible. Comparisons were made across the six plans for each attribute to evaluate the extent to which each plan met the broader objectives. The measures were provided to the Advisory Group at the November 15, 2004 HECO IRP-3 Advisory Group meeting. A copy of the attributes and measures is provided on the attached pages 4 to 7.

c. Customers' energy needs may be satisfied by a number of sources, including solar water heating, heat from heat pumps or CHP units, small distributed generation (which may be fossil-fueled units or renewable energy technologies such as photovoltaic or wind units) on customer sites, electricity from the utility grid (where such power may be generated from oil, coal or renewable resources), or gas.

In 2004, 77% of the electricity generated on Oahu came from oil-fired units, 19% came from a coal-fired unit, and 4% came from a municipal solid waste unit (H-Power).

With respect to fuel diversity provided by renewable resources, the attached Renewable Portfolio Standards report, submitted to the Commission on February 27, 2004, provides additional information. (See pages 8 to 33 to this response.)

d. Since 1990, the trend has been toward greater fuel diversity. In early 1990, HECO had 1,209 MW (net) of firm generating capacity, all of which was oil-fired. At the time, HECO was purchasing power on an as-available basis from Makani Uwila Power Corporation (Kahuku Wind Farm – up to 16 MW), Oahu Sugar Company (biomass – up to 16 MW), Waialua Sugar Company (biomass – up to 12 MW). In May 1990, the 46 MW municipal solid waste generating unit (H-Power) began providing firm power to HECO. In June 1990, Kapaa Generating Partners began providing up to 3 MW of power from a landfill gas-fueled generating unit to HECO on an as-available basis. In 1991, Kalaeloa Partners, LP, began providing 180 MW of firm capacity from oil-fired generating units. In 1992, AES-Barbers Point (now AES Hawaii) began providing 180 MW of firm capacity from a coal-fired generating unit. Oahu Sugar Company, Makani Uwila Power Corporation, Waialua Sugar Company, and Kapaa Generating Partners ceased operations in 1995, 1996, 1998 and 2002, respectively. As indicated in part c., in 2004, 23% of electricity generation came from non-oil sources.

e. HECO does not have a specific fuel diversity target. The appropriate amount of fuel diversity must consider factors such as the cost and availability of various types of fuels, the ability of existing generating units to utilize alternative fuels, the cost of alternative types of future generating units that can utilize alternative fuels, the cost of renewable resources, and the overall cost-effectiveness of achieving various levels of fuel diversity. In addition, fuel diversity must be considered along with the other objectives and attributes identified in response to parts b. and c. above.

Plan 3	Plan 4	Plan 5	Plan 6
Maximize Renewable Energy Plan	Meets the State RPS Law	Maximize Fuel Diversity Plan	Combination Plan
water will not be used oling source ed potable water use ass crop use of fossil fuels te to lower risk of of potable water by s crop increases water supply by seeding putting water into and reducing runoff	-Potable water will not be used as a cooling source -Higher use of fossil fuels contribute to higher risk of pollution of potable water by fuel oil -Higher use of fossil fuels contribute to global warming, cause rise in ocean levels & reduce potable supply	-Potable water will not be used as a cooling source -Higher use of fossil fuels contribute to higher risk of pollution of potable water by fuel oil and coal -Higher use of fossil fuels contribute to global warming, cause rise in ocean levels & reduce potable supply	-Potable water will not be used as a cooling source -Higher use of fossil fuels contribute to higher risk of pollution of potable water by fuel oil and coal -Higher use of fossil fuels contribute to global warming, cause rise in ocean levels & reduce potable supply
isk of a fuel spill due to portation of petroleum s contribution to global l sediment build up on nce agriculture reduces	-Higher level of importation of petroleum products increases risk of a fuel spill -Higher use of fossil fuels contribute to global warming, cause rise in ocean levels	-Higher level of importation of petroleum products increases risk of a fuel spill -Higher use of fossil fuels contribute to global warming, cause rise in ocean levels	-Higher level of importation of petroleum products increases risk of a fuel spill -Higher use of fossil fuels contribute to global warming, cause rise in ocean levels
ve use of land for wind, nass, MSW resources lot of green space from crop risk of impact on ed and endangered mount of wind would d locked into non-urban reduce landfill buildup isk of fuel spills contribution to global	-Moderate use of land for wind, resource -Moderate risk of impact on threatened and endangered species -Increased risk of fuel spills -Higher use of fossil fuels contribute to global warming, cause rise in ocean levels & reduce land mass	-Moderate use of land for wind, resource -Moderate risk of impact on threatened and endangered species -Increased risk of fuel spills -Higher use of fossil fuels contribute to global warming, cause rise in ocean levels & reduce land mass	-Moderate use of land for wind, resource -Moderate risk of impact on threatened and endangered species -Increased risk of fuel spills -Higher use of fossil fuels contribute to global warming, cause rise in ocean levels & reduce land mass
153,147,339	158,969,856	165,013,902	158,364,351
9,359	9,031	9,010	9,380
56,104	48,653	51,075	51,056
34,419	35,685	34,425	34,649
320,389	331,021	283,823	320,380
301,212	319,479	294,621	304,650

2.	**Economical Electricity**								
a.	Utility Accumulated present worth of revenue requirements (including transmission line capital projects)	Dollars PW Year 2003 $(000)	6,915,289	**6,734,325**	**7,219,442**	**7,720,972**	**6,744,260**	**7,068,748**	**6,825,055**
b.	"Average rate" impact over 20-year planning period (residential, commercial, industrial)	¢/kWh Nominal	17.77 15.39 12.74	**17.63** **15.27** **12.64**	**18.95** **16.44** **13.61**	**19.98** **17.35** **14.37**	**17.67** **15.30** **12.66**	**17.74** **15.37** **12.73**	**17.87** **15.47** **12.81**
c.	Total Resource Cost (TRC)	Dollars PW Year 2003	7,214,315	**7,176,157**	**7,661,275**	**8,162,805**	**7,186,093**	**7,262,926**	**7,266,887**
	End Effects	Dollars PW Year 2003	3,479,309	**3,283,743**	**3,550,872**	**3,746,588**	**3,289,325**	**3,325,054**	**3,271,602**
	Study Period Total Resource Cost	Dollars PW Year 2003	10,693,623	**10,459,900**	**11,212,147**	**11,909,393**	**10,475,418**	**10,587,979**	**10,538,489**
	Societal Cost	Dollars PW Year 2003	7,352,386	**7,296,826**	**7,779,785**	**8,279,438**	**7,306,591**	**7,378,666**	**7,384,575**
d.	Typical residential monthly bill impact	Dollars Nominal	106.63	**105.81**	**113.71**	**119.88**	**106.00**	**106.42**	**107.20**
e.	Impact to the State economy			Minimal	Minimal	Minimal	Minimal	Minimal	Minimal
	"Average" Real Gross State Product	Dollars PW Year 2003	N/A	**61,926**	**61,999**	**61,924**	**61,909**	**61,935**	**61,937**
	"Average" Real Household Expenditures	Dollars PW Year 2003	N/A	**32,436**	**32,420**	**32,384**	**32,429**	**32,424**	**32,418**
	Employment Created	Person-Years	N/A	**1,874**	**1,884**	**1,892**	**1,874**	**1,882**	**1,878**
3.	**Power Quality and Reliability**								
a.	Generating system reliability	Years per Day	13.9	**21.3**	**20.8**	**26.2**	**21.3**	**24.0**	**25.6**
b.	Appropriate mix of baseload, cycling and peaking generating capacity			-Two new peaking units are preferred additions to existing generation	- Peaking capacity preferred. Plan includes one additional peaking unit -Biomass and MSW resources are fixed dispatch type units, which provides operational constraints	- Peaking capacity preferred. Plan includes one additional peaking unit -Biomass and MSW resources are fixed dispatch type units, which provides operational constraints	-Two new peaking units are preferred additions to existing generation	- Peaking capacity preferred. Plan includes one additional peaking unit	- Peaking capacity preferred. Plan includes one additional peaking unit
c.	System power quality			No new intermittent or fixed dispatch resources	-High levels of intermittent (as-available) wind and PV resources will have an impact on operational system power quality	-High levels of intermittent (as-available) wind and PV resources will have an impact on operational system power quality	-Moderate levels of intermittent (as-available) wind resources will have a moderate impact on operational system power quality	-Moderate levels of intermittent (as-available) wind resources will have a moderate impact on operational system power quality	-Moderate levels of intermittent (as-available) wind resources will have a moderate impact on operational system power quality

rces	-Low use of oil for new resources. New resources use oil, coal, wind, and solar
	65.2
	8,724
	8,878
	168.7
	10,418
	8,706
	12.9%
	13.6%
	14.4%
	1,323,871,915
	366,231,049
vind sitive	-Potential for siting of wind farms on culturally sensitive sites
for multi r wer or d ture under	-Moderate use of land for wind resource -Moderate benefit from multi purpose use of land for wind -Moderate benefit of lower density development for land extensive RE resources such as wind -Requires siting of new transmission infrastructure outside areas already under similar use
	920
	855
	65
	74

6.	**Increase Plan Flexibility**								
a	Resilience under sensitivity analysis			Less resilient under high fuel price scenarios	-Renewables add cost stability with higher fossil fuel costs	-Renewables add cost stability with higher fossil fuel costs		-The coal unit adds cost stability with higher fuel price scenarios	-The coal unit adds cost stability with higher fuel price scenarios
b	Flexibility of plan resources			-Large CHP market increases flexibility	-Large CHP market increases flexibility -Large amount of small PV resources provide for a greater amount of flexibility	-Large CHP market increases flexibility -Large amount of small PV resources provide for a greater amount of flexibility	-Large CHP market increases flexibility	-Small CHP market provides less flexibility	-Large CHP market increases flexibility
7.	**Utility Financial Integrity & Competitiveness**								
a.	Total Capital	Dollars PW Year 2003 $(000)	744,340	**206,860**	**1,116,040**	**1,880,890**	**255,500**	**683,650**	**691,561**
	Generation Capital	Dollars PW Year 2003 $(000)		**139,040**	**1,035,630**	**1,799,600**	**185,320**	**611,150**	**619,061**
	Transmission Capital	Dollars PW Year 2003 $(000)		**67,820**	**80,410**	**81,290**	**70,180**	**72,500**	**72,500**
b.	Annual revenue requirements in the first 10 years of the plan	Dollars PW Year 2003 $(000)	4,195,177	**4,160,071**	**4,215,297**	**4,480,326**	**4,160,071**	**4,280,078**	**4,197,584**
c.	Rate impact over the first 10 years of the plan	¢/kWh Nominal	13.39	**13.38**	**13.55**	**14.26**	**13.38**	**13.28**	**13.48**

February 27, 2004

The Honorable Chairman and Members of the
Hawaii Public Utilities Commission
465 South King Street
Kekuanaoa Building, 1st Floor
Honolulu, Hawaii 96813

Dear Commissioners:

Subject: HECO, HELCO and MECO
Renewable Portfolio Standards Status Report

HECO, HELCO, and MECO respectfully submit its Renewable Portfolio Standards (RPS) Status Report for 2003. The report reviews the status of the RPS percentage for HECO, HELCO and MECO. It also explains our policy position and strategy regarding the Hawaii RPS

Renewable Portfolio Standards
Status Report to the Hawaii Public Utilities Commission
2003

Prepared by:

Hawaiian Electric Company, Incorporated
Hawaii Electric Light Company, Incorporated
Maui Electric Company, Limited

February 27, 2004

Renewable Portfolio Standard Status Report
For the year ended December 31, 2003

Executive Summary

RPS Results for 2003

Hawaiian Electric Company and its subsidiaries, Hawaii Electric Light Company and Maui Electric Company ("the HECO utilities") are very pleased to have achieved in 2003 a consolidated Renewable Portfolio Standard (RPS) percentage of 8.40% (Figure 2). This is a significant increase over the 6.76% RPS percentage reported for 2002 and exceeds the RPS goal of 7% for 2003.

The increase from 2002 was primarily caused by the return to near-normal output levels of Puna Geothermal Venture after well problems in 2002 (i.e. from about 5 MW in 2002 to about 27 MW in 2003) a 12% increase in electricity produced by the HPOWER facility and an increased use of bagasse at HC&S. This highlights the great variation from year to year in electricity production from renewable energy sources. The increase in the RPS percentage from 2002 was also caused by a first-time adjustment to include a portion of the output from AES which represents the amount of old tires, used oil, and used carbon filters utilized as fuel.

The increases in 2003 were offset by reduced hydroelectric generation due to a catastrophic equipment failure at Puueo Hydro on the Big Island as well as drought conditions on the Big Island during a significant portion of the year.

However, a note of caution is also essential. Although the 2003 percentage of 8.40% exceeds the RPS goal of 7% for 2003, this level may be difficult to maintain. Even if the amount of renewable energy remains at 2003 levels in future years (not at all a certainty as the problems experienced in 2002 drove home), the RPS percentage may decline because electric sales (the denominator in the calculation) continue to increase as the economy grows (see Figure 3). In fact, recent news of increased economic activities including increased military activities, such as the addition of a Stryker brigade and C-17 squadron, could result in even higher sales than currently forecast for Oahu. The point is simply that Hawaii's use of electricity is growing and therefore renewable production must grow or the RPS numbers will slip.

RPS Projections for 2005 and 2010

With the attainment of the 7% goal for 2003 – the first year targeted in the RPS law – it is now appropriate to look ahead toward the targets for 2005 and 2010. To help assess the reasonableness of RPS goals for the future, a projection of future RPS percentages is provided. This projection requires a forecast of electricity sales and an estimate of future renewable energy usage. The sales forecast used to make the projection is the latest available for each utility. The estimate of future renewable energy usage is divided into two parts:

(1) Estimates of the renewable energy from *existing* projects.
(2) Estimates of the renewable energy from *new projects* that have been proposed.

Given the variable nature of the electricity generation from renewable energy projects, future renewable energy from existing projects generally was estimated to be the average of the electricity generation from the last five years. Regarding estimates of future renewable energy from new projects, HECO, HELCO and MECO are involved in many activities to bring more renewable energy onto their utility systems (see section 5 of this report).

The calculations in Figure 4 indicate that given preliminary assumptions about the timeframe for completion of proposed projects, the amount of renewable energy on the system is expected to increase through 2010. Given the current forecast, we can hopefully meet or slightly exceed the 8% RPS level in 2005. With some fairly optimistic assumptions about specific future renewable energy projects, it also appears possible to meet the 9% RPS in 2010.

Though we are committed to doing everything we can to achieve these preliminary projections, they are provided with the strong caveat that there are many variables impacting the actual development of renewable projects. For example, a renewable energy developer may be unable to obtain State or County permits, land lease, project financing, or community support. In addition, the developer may not be able to locate the renewable resource, or once operational, may be unable to keep its facility operating. Also, it is not simply a matter of whether a given technology is feasible; it also frequently requires additional infrastructure such as power lines to connect the renewable project to the electric grid. This infrastructure also must be permitted, a challenge which may be more formidable than permitting the renewable energy generation itself. Expiration of tax credits such as the Federal Production Tax credit (wind) or the state Energy Conservation Income Tax Credit (wind, solar water heating) can also have negative impacts on renewable energy.

The following is a list of some of the reasons for failed renewable energy projects in the State:

- Inability to secure permits (hydroelectric on Kauai);
- Inability to secure land lease (10 MW wind on Maui);
- Poor economics or inability to secure project financing (40 MW OTEC on Oahu, sugar mills on Hawaii, Maui, Oahu and Kauai, 9 MW wind on Oahu, 2 MW wind on Big Island);
- Community opposition (6 MW hydroelectric on Kauai, 2-4 MW hydroelectric on Maui, 14 MW hydroelectric on Hawaii, and hydroelectric on Molokai, 1 MW wind on Oahu);
- Unavailability of renewable resources (early geothermal projects on Hawaii, 4 MW biomass on Molokai); and
- Operational problems (1 MW wind on Molokai).

In addition, planning for a major wind project on the Big Island was significantly delayed because the potential developer was an Enron subsidiary at a time when Enron was distracted by its own corporate difficulties.

Any one of these factors, which are outside of the utilities' direct control, could prevent, delay or shut down a renewable energy project.

HECO Utilities' RPS Strategy

Despite these challenges, the HECO utilities take the RPS law very seriously and have demonstrated through our actions a strong commitment to achieving these levels. We strongly support the Hawaii State Energy Goal for "increased energy self-sufficiency where the ratio of indigenous to imported energy use is increased."

To this end HECO, MECO and HELCO are executing a strategy that incorporates myriad activities, but which can be grouped into two main thrusts to increase its renewable energy portfolio:

(1) Pursue commercial renewable energy projects; and

(2) Accelerate the development of emerging renewable energy technologies that have potential for commercial application.

This strategy aims to pursue commercially available renewable energy generation in the near term, and in parallel, to invest in research, development, and demonstration projects (RD&D) for emerging technologies and resources that are not currently commercially available or economically viable in the near term. This strategy will ensure that the HECO utilities are not only taking action to use as much renewable energy as is commercially and economically viable today, but also are helping to develop future sources of renewable energy.

Section 5 provides a very detailed list of the current activities the HECO utilities are engaged in to help reduce Hawaii's use of imported oil and meet the RPS targets.

Conclusion

HECO, HELCO and MECO are very pleased to have met the initial 7% target for 2003. Looking ahead, although preliminary projections are hopeful, given the variables which can impact potential renewable projects, we believe it is premature to draw definite conclusions about the achievability of the future goals of 8% in 2005 and 9% in 2010 or to set targets beyond 2010. But as the detailed report illustrates, despite the variables and challenges, we are actively working on many fronts to support and develop projects that will give us every opportunity to achieve these important goals for our State. What we most need is an equally strong commitment by the public sector to doing its part to help make the goals achievable.

Renewable Portfolio Standard Status Report
For the year ended December 31, 2003

1.0 Introduction – Purpose of report

The 2001 Hawaii State Legislature passed a law introducing a Renewable Portfolio Standard (RPS) for Hawaii. Act 272, codified as Hawaii Revised Statutes (HRS) section 269.91 through 269.94, established RPS levels for electric utilities to guide them in incorporating renewable resources into their resource portfolios and to reduce Hawaii's use of imported oil.

The purpose of this report is to review the status of the RPS percentage for the Hawaiian Electric Company (HECO) utilities for the calendar year 2003 in accordance with Hawaii Revised Statutes (HRS) 269-92. This document also explains the policy position and strategy of Hawaiian Electric Company, Inc., Hawaii Electric Light Company, Inc. and Maui Electric Company, Ltd. (together referred to as HECO utilities) regarding the Hawaii RPS law.

2.0 Policy Statement

HECO and its subsidiaries Maui Electric Company (MECO) and Hawaii Electric Light Company (HELCO) strongly support the Hawaii State Energy Goal for "increased energy self-sufficiency where the ratio of indigenous to imported energy use is increased."

To this end HECO, MECO and HELCO follow two basic tracks for the development and application of renewable energy.

The first is the application of commercially viable, cost-effective renewable energy technologies to the electric grid. This can be achieved through the development and implementation of renewable energy projects directly by HECO, by the contracting of renewable energy from independent power producers and by the investment of HECO's subsidiary, Renewable Hawaii, Inc., into commercially viable projects.

The second track is the research and development of renewable energy technologies that are not yet economic but have potential in the future to increase Hawaii's energy self-sufficiency. HECO recognizes and supports the goal of cultivating the promise of emerging renewable technologies through partnerships between the public and private sectors. Such partnerships not only provide for the leveraging of resources, they also capitalize on Hawaii's unique opportunities to be a center for the testing and demonstration of renewable energy technologies.

3.0 RPS Background

3.1 Description of State RPS Law (HRS-269.91 – 94)

HRS 269.91 through 94 state that the RPS is the percentage of electricity sales that is represented by renewable energy. Renewable energy is the electrical energy produced by wind, solar energy, hydropower, landfill gas, waste-to-energy, geothermal resources, ocean thermal energy conversion, wave energy, biomass including municipal solid waste, biofuels or fuels derived from organic sources, hydrogen fuels derived entirely from renewable energy, fuel cells where the fuel is derived entirely from renewable resources, or the savings brought about by the use of solar and heat pump water heating. The HRS further specifies that the RPS levels shall be 7% of electricity sales by December 31, 2003, 8% by December 31, 2005, and 9% by December 31, 2010. An electric utility company and its electric utility affiliates may aggregate their renewable portfolios in order to achieve the RPS.

3.2 Description of RPS in other jurisdictions

RPS has been investigated in other jurisdictions and a number of them have enacted legislation or regulation establishing RPS. Several jurisdictions investigated RPS as part of their electricity deregulation efforts using RPS as a vehicle to ensure that electricity from renewable energy will continue to have a market even under full retail electricity competition. Although interest in electricity deregulation has somewhat diminished, RPS continues to be debated in the legislative and regulatory arena. Figure 1 shows a comparison of RPS enacted in other jurisdictions.

The RPS requirements in other jurisdictions range from 1.1% in 2012 for Arizona and 2.2% by 2011 for Wisconsin, up to 20% in 2017 for California and 30% in 2000 for Maine. It is important to note that California and Maine have existing hydroelectric dam facilities that contribute towards meeting their RPS requirements. In all, there are 15 states (Arizona, California, Connecticut, Hawaii, Illinois, Iowa, Maine, Massachusetts, Minnesota, Nevada, New Jersey, New Mexico, Pennsylvania, Texas, and Wisconsin) that have some form of RPS.

Part of the controversy with RPS requirements is the establishments of specific penalties for non-attainment of the RPS percentage targets. Several jurisdictions have very substantial penalties (e.g. 5.5 cents/kWh in Connecticut). There has been at least one instance (i.e. Arizona) where penalties had a negative effect on the utility to the detriment of ratepayers resulting in repeal of the penalties. At least six states (Arizona, California, Hawaii, Illinois, Minnesota, and Pennsylvania) do not specify penalties.

Figure 1

RPS – Adopted by Legislation/Regulatory Action

	State	Eligible Resources/Technologies[2]	Requirements	Current RE Level[2,3]
1	**ARIZONA** *Regulatory action (1999)* *Docket No. E00000A-99-205* *Rules* *R14-2-1618* *"Environmental Portfolio Standard"*	Solar: PV, STE, SWH Other: LG, W, B	0.2% in 2001; annual +0.2% to 2005; 1.05% in 2006; 1.1% in 2007-2012 Sub-requirement: 60% of EPS level from PV/STE by 2007 Annual increase after 12/31/04 contingent upon conditions set by ACC (findings of Cost Evaluation Working Group due to ACC by 6/3/03).	9.4% (with hydro) 0.01% (without hydro) H, Other
2	**CALIFORNIA** *Legislation (2002)* *SB 1078* *"Renewables Portfolio Standard"*	STE, PV, LG, W, B, H, G, MSW Restrictions on G, H, and MSW	Increase of 1% per year beginning 2003; 20% by end of 2017	29.4% (with hydro) 10.9% (without hydro) H, G, PV, W, MSW/LG, S B, Other
3	**CONNECTICUT** *REVISED: Legislation (2003)* *SB 733* *Public Act No. 03-135* *Rules* *CT PUC licensing, 16-245-5* *"Renewable Portfolio Standard"*	Class I: S, W, H (< 5 MW), SB, LG, FC, OT, OW, T Class II: H, MSW, B RE facility emissions cap (NOx per million Btu)	All years: 3% from Class I or II 4% total in 2004 (1% from Class I); +0.5% per year from Class I until 2006 6.5% total in 2007 (3.5% from Class I) 8% total in 2008 (5% from Class I); +0.5% per year from Class I until 2010 10% total in 2010 (7% from Class I)	8.0% (with hydro) 6.4% (without hydro) H, MSW/LG, Other
4	**HAWAII** *Legislation (2001)* *HB173 CD1: Act 272* *"Renewables Portfolio Standard"*	W, S, H, LG, MSW, G, OT, OW, B, BF, FC, H2 (FC must utilize renewable fuels)	7% by end of 2003; 8% by end of 2005; 9% by end of 2010	8.6% (with hydro) 7 [illegible]% (without hydro) H, G, W, MSW/LG, B, Other

4.0 Current Renewable Energy Situation and Projections for 2005 and 2010

4.1 HECO Utilities' RPS levels for 2003

The HECO utilities are very pleased to have achieved in 2003 a consolidated RPS percentage of 8.40% (Figure 2). This is a significant increase over the 6.76% RPS percentage reported for 2002 and exceeds the RPS goal of 7% for 2003.

The increase from 2002 was primarily caused by the return to near-normal output levels of Puna Geothermal Venture after well problems in 2002 (i.e. from about 5 MW in 2002 to about 27 MW in 2003), a 12% increase in electricity produced by the HPOWER facility, and an increased use of bagasse at HC&S. This highlights the great variation from year to year in electricity production from renewable energy sources. The increase in the RPS percentage from 2002 was also caused by a first-time adjustment to include a portion of the output from AES which represents the amount of old tires, used oil, and used carbon filters utilized as fuel.

The increases in 2003 were offset by reduced hydroelectric generation due to a catastrophic equipment failure at Puueo Hydro on the Big Island as well as drought conditions on the Big Island during a significant portion of the year.

Information on specific renewable energy projects is provided in Section 5.1.

Figure 2

Renewable Portfolio Standard 2003 Status Report

Hawaiian Electric Company, Inc.
Hawaii Electric Light Company, Inc.
Maui Electric Company, Ltd.

Year-to-Date as of December 31, 2003

	GWh
HECO	
H-POWER	338
AES	30
Photovoltaic Systems	0.2
Solar Water Heating[1]	38
Solar Water Heating (Pre-DSM Systems)[2]	73
Heat Pump[3]	5
Subtotal	484
HELCO	
PGV	176
Hydro-Wailuku	24
Hydro-HELCO owned	2
Wind-Lalamilo Wells	2
Small Hydro	1
Other Wind including Kamaoa	10
Photovoltaic Systems	1.4
Solar Water Heating[1]	8
Solar Water Heating (Pre-DSM Systems)[2]	14
Heat Pump[3]	0.3
Subtotal	239
MECO	
Biomass & Hydro-HC&S[4]	66
Photovoltaic Systems	0.2
Solar Water Heating[1]	13
Solar Water Heating (Pre-DSM Systems)[2]	17
Heat Pump[3]	2
Subtotal	98
TOTAL Renewable Energy (GWh)	**821**
TOTAL Sales[5] (GWh)	**9,775**
RPS Percentage[6]	**8.40%**

Energy Savings From DSM Programs (GWh)[7] 397

Footnotes:

1. Act 272 specifies that renewable energy include the electrical energy savings brought about by the use of solar water heating. The gigawatt hour (GWh) for solar water heating is based upon the energy savings from solar water heating systems installed under the utility's demand-side management programs. The energy savings from utility demand-side management programs are reported to the Public Utilities Commission and the Consumer Advocate and are verified by an independent consultant whose evaluation reports are also filed with the Public Utilities Commission and the Consumer Advocate.

2. Pre-DSM solar water heating systems represent an estimate of energy saved by solar water heating system in operation today that were installed prior to the inception of the utility DSM programs in 1996. This estimate is based on a survey of appliance usage by customers of HECO, HELCO, and MECO.

3. Act 272 specifies that renewable energy include the electrical energy savings brought about by the use of heat pump water heating. The GWh for heat pumps is based upon the energy savings from heat pump systems installed under the utility's demand-side management programs.

4. HC&S utilizes bagasse (i.e. sugar cane residue) and hydropower, which are sources of renewable energy, in addition to coal and oil to generate the electricity it sells to MECO. Renewable energy is estimated to be 80.9% of the electricity sold to MECO based on recorded 2003 information provided by the Department of Business, Economic Development and Tourism.

5. Electricity sales for the period January 1, 2003 through December 31, 2003 were 7,522 GWh for HECO, 1,046 GWh for HELCO, and 1,207 GWh for MECO.

6. Renewable energy is defined in Act 272 to include the electrical energy savings brought about by the use of solar and heat pump water heating. Since solar and heat pump water heating are included with renewable energy and also reduce the amount of electricity sales, the renewable portfolio standards percentage might be viewed as double counting the benefits of solar and heat pump water heating. If the energy savings of 163 GWh were added back into the electricity sales, then the renewable portfolio standards percentage would be 8.26%.

7. Provided for reference only. One of the goals of the RPS is to reduce the State's use of oil. That end is accomplished by the use of both renewable energy AND energy efficiency. Although the RPS law does not include energy efficiency savings, for reference purposes, this is the estimated amount of energy saved during the 2003 in GWh by all participants in the HECO, HELCO and MECO-sponsored demand-side management (energy efficiency) programs to date (i.e. since the start of the programs in 1996 including solar water heating and heat pumps).

4.2 HECO Utilities RPS Projections for 2005 and 2010

With the attainment of the 7% goal for 2003 – the first year targeted in the RPS law – it is now appropriate to look ahead toward the targets for 2005 and 2010. To help assess the reasonableness of RPS goals for the future, a projection of future RPS percentages is provided. This projection requires a forecast of electricity sales and an estimate of future renewable energy usage. The sales forecast used to make the projection is the latest available for the specific utility. The estimate of future renewable energy usage is divided into two parts:

(1) Estimates of the renewable energy from *existing* projects.
(2) Estimates of the renewable energy from *new projects* that have been proposed.

Given the variable nature of the electricity generation from renewable energy projects, future renewable energy from *existing* projects except for geothermal generally was estimated to be the average of the electricity generation from the last five years. For geothermal, the average output for the last nine months of 2003 was used because of the changes PGV made to its production and re-injection wells to correct problems experienced in 2002 and early 2003. Future energy savings from solar water heating and heat pumps are based on estimates from the utility demand-side management programs and an estimated burn-out rate of 6.7% for pre-DSM solar water heating systems. Renewable energy from photovoltaic systems was estimated to increase at 10% per year. The estimate of renewable energy from existing sources is shown in Figure 3.

Regarding estimates of future renewable energy from *new projects*, HECO, HELCO and MECO are involved in many activities to bring more renewable energy onto their utility systems (see section 5 of this report).

Figure 3

Existing Renewable Energy Sources (GWh)

	Historical					Projections [1]						
	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
HECO Renewable Energy (GWh)												
HPOWER	314	316	282	300	338	310	310	310	310	310	310	310
Kapaa Landfill Gas [2]	13	9	7	2	-	-	-	-	-	-	-	-
Municipal Solid Waste - AES [3]	-	-	14	25	30	30	30	30	30	30	30	30
Photovoltaic Systems [4]	-	-	-	-	0.2	0.2	0.2	0.3	0.3	0.3	0.4	0.4
Solar Water Heating	19	24	25	30	38	43	48	53	58	63	68	73
Solar Water Heating (pre-DSM systems) [5]	78	78	78	78	73	68	62	57	52	47	41	36
Heat Pump	3	4	4	5	5	5	5	5	5	5	5	5
Subtotal:	427	431	410	440	484	456	455	455	455	455	454	454
Estimated Oil Saved *(Thousand Barrels)*	710	720	680	730	810	760	760	760	760	760	760	760
HELCO Renewable Energy (GWh)												
PGV [1,6]	196	250	207	74	176	210	210	210	210	210	210	210
Hydro-Wailuku	27	29	33	27	24	28	28	28	28	28	28	28
Hydro-HELCO owned	19	15	18	9	2	13	13	13	13	13	13	13
Wind-Lalamilo Wells	4	3	2	2	2	3	3	3	3	3	3	3
Other Hydro	2	1	1	1	1	1	1	1	1	1	1	1
Wind-Kamaoa	12	13	15	10	10	12	12	12	12	12	12	12
Photovoltaic Systems	-	-	-	-	1.4	1.5	1.7	1.8	2.0	2.2	2.4	2.7
Solar Water Heating	4	5	5	6	8	9	10	11	12	13	14	15
Solar Water Heating (pre-DSM systems) [5]	15	15	15	15	14	13	12	11	10	9	8	7
Heat Pump	-	-	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.4	0.4
Subtotal:	279	331	296	144	239	291	291	291	291	292	292	292
Estimated Oil Saved *(Thousand Barrels)*	620	740	660	320	530	650	650	650	650	650	650	650
MECO Renewable Energy (GWh)												
Biomass and Hydro-HC&S [7]	53	45	38	69	66	54	54	54	54	54	54	54
Biomass-Pioneer Mill [8]	2	0	0	0	0	0	0	0	0	0	0	0
Photovoltaic Systems	-	-	-	-	0.2	0.2	0.3	0.3	0.3	0.3	0.4	0.4
Solar Water Heating	5	7	7	10	13	15	17	19	20	22	24	26
Solar Water Heating (pre-DSM systems) [4]	18	18	18	18	17	15	14	13	12	11	9	8
Heat Pump	-	-	1.6	1.9	2.0	2.1	2.1	2.0	2.1	2.1	2.1	2.1
Subtotal:	78	70	65	99	98	86	87	88	88	89	90	91
Estimated Oil Saved *(Thousand Barrels)*	140	120	110	170	170	150	150	150	150	150	160	160

Footnotes:

1. Future renewable energy GWhs projections are based upon the historical Gwh average (1999-2003), except for AES, PGV, Photovoltaic Systems, Solar Water Heating, and Heat Pumps.
2. Kapaa Landfill gas project ceased generating electricity in 2002 due to equipment failure.
3. AES Municipal Solid Waste energy is based on the amount of energy derived from shredded used tires, waste oil, and used activated carbon. Future GWhs are assumed to be the same as the amount in 2003.
4. Photovoltaic assumed to grow at a rate of 10% per year with a capacity factor of 20%.
5. Pre-DSM solar water heating systems represent an estimate of energy saved by solar water heating systems in operation today that were installed prior to the inception of the utility DSM programs in 1996. The 2002 GWh estimate is based on a survey of appliance usage by customers of HECO, HELCO, and MECO. Projections (2003-2010) are based upon an estimated burn out rate of 6.7% per year.
6. PGV total output for 2002 was significantly lower due to well problems. Future PGV output based upon the average output of 17.5 GWhs per month during Apr.-Dec. 2003.
7. HC&S biomass and hydro energy in 2003 is estimated to be 80.9% of their total energy sold to MECO base on recorded 2003 information from DBEDT. Renewable energy contribution for 2008 and beyond depends on the continutation or establishment of a new power purchase agreement.
8. 1999 was the last year Pioneer Mill sold power to MECO. Pioneer Mill has since ceased operations.
9. Sales Forecast data reduced for impacts from DSM and 3rd party Combined Heat and Power:
   - HECO: August 2002 Sales and Peak Forecast adjusted for 2003 actuals
   - HELCO: May 13, 2003 Sales & Peak Forecast extended to 2010
   - MECO: June 26, 2003 Sales & Peak Forecast extended to 2010
10. The RPS percentage for 2001 is an update of the number previously reported to reflect MSW from AES, pre-DSM solar water heaters, and actual renewable energy utilization from HC&S. The RPS percentage for 2001 that was previously reported was 6.92%.
11. The RPS percentage for 2002 is an updated of the number previously reported to reflect MSW from AES and actual renewable energy utilization from HC&S. The RPS percentage for 2002 that was previously reported was 6.76%.

Projections for new renewable energy projects that have been proposed are shown in Figure 4. The projection uses a probabilistic approach that factors the uncertainty in timing of the project into the total estimate of renewable energy. The probability that a project will be completed in the specified year (based on the nature of the project, the existence of a signed power purchase contract in the case of one wind project, and past experience) is multiplied by the estimated electricity output. The result is summed for all projects yielding an expected value of total renewable energy for the specified year. The probability of project completion is estimated to increase over time to reflect the assumption that if a project developer is not able to complete a project, another developer would take over the project. The case in point is Kaheawa Wind farm on Maui, which was originally proposed by Zond Pacific, was taken over by GE Wind Energy, and subsequently by Hawi Renewable Development. At the same time, the probabilities of project completion do not reach 100 percent, as there is no guarantee that a proposed project will be completed. The most recent example of this is the Kahua Power Partners wind farm project, which had all of the required approvals by permitting agency including Public Utilities Commission approval of the Power Purchase Agreement, and yet the project ended up being canceled by the project developer (in order to allow for expansion of another wind farm project.).

The exception to the probabilistic approach is geothermal expansion because the proposed geothermal expansion projects are at very early stages making it difficult to estimate the probability of completion. The projected RPS percentages for both cases (expansion takes place and does not take place) are provided so that readers can make their own decision on the probability of project completion. In addition, given the relatively small size of the Big Island electric grid, there is an issue of how much electricity can be utilized from new generation sources, especially during the early morning periods of low electricity demands. The projected RPS percentages are provided for two different capacity factors (i.e. ratio of average load on the generating unit to the capacity rating) for geothermal expansion.

Figure 4

Proposed Renewable Energy Projects [1]

	Projections							PGV 8MW Increment Capacity Factor [11]		PGV 22MW Increment Capacity Factor [11]	
								@50 %	@ 70%	@ 50%	@ 70%
	2004	*2005*	*2006*	*2007*	*2008*	*2009*	*2010*	*2010*	*2010*	*2010*	*2010*
Proposed Oahu RE Projects											
Waste Gas (1 MW) [2]											
- Probability of project completion	-	-	50%	70%	80%	90%	90%				
- Estimated Energy Output (GWh) [3]	-	-	4	6	6	7	7	7	7	7	7
Municipal Solid Waste (16 MW Increment) [4]											
- Probability of project completion	-	-	-	-	50%	60%	70%				
- Estimated Energy Output (GWh) [3]	-	-	-	-	46	55	64	64	64	64	64
***Estimated Oil Saved** (Thousand Barrels)*	-	-	7	10	90	100	120	120	120	120	120
Proposed Big Island RE Projects											
Wind-Kamaoa Repower (20 MW) [5,6]											
- Probability of project completion	-	-	50%	60%	70%	80%	90%				
- Estimated Energy Output (GWh) [3]	-	-	19	25	31	37	43	43	43	43	43
Wind-Hawi (10.6 MW) [5,7]											
- Probability of project completion	-	-	70%	80%	80%	90%	90%				
- Estimated Energy Output (GWh) [3]	-	-	23	26	26	29	29	29	29	29	29
Wood Waste Generation [8]											
- Probability of project completion	-	-	-	-	-	-	-				
- Estimated Energy Output (GWh) [3]	-	-	-	-	-	-	-	-	-	-	-
PGV (8 MW Increment) [9] See Col. Descript											
- Estimated Energy Output (GWh) [3]	-	-	-	-	-	-	-	35	49	-	-
PGV (22 MW Increment) [9, 10] See Col. Descript											
- Estimated Energy Output (GWh) [3]	-	-	-	-	-	-	-	-	-	96	135
***Estimated Oil Saved** (Thousand Barrels)*	-	-	90	110	130	150	160	240	270	380	460
Proposed Maui RE Projects											
Wind-Kaheawa (17.8 MW) [5,12]											
- Probability of project completion	-	-	50%	60%	70%	80%	90%				
- Estimated Energy Output (GWh) [3]	-	-	27	33	38	44	49	49	49	49	49
***Estimated Oil Saved** (Thousand Barrels)*	-	-	50	60	70	80	90	90	90	90	90
TOTAL Renewable Energy of Proposed Projects (GWh)	0	0	73	89	147	172	192	227	241	289	327
RPS Percent for Proposed Projects	**0.0%**	**0.0%**	**0.7%**	**0.8%**	**1.4%**	**1.6%**	**1.8%**	**2.1%**	**2.2%**	**2.7%**	**3.0%**

Projection of Future RPS Percentage

	Projections							PGV 8MW Increment Capacity Factor [11]		PGV 22MW Increment Capacity Factor [11]	
								@ 50%	@ 70%	@ 50%	@ 70%
	2004	*2005*	*2006*	*2007*	*2008*	*2009*	*2010*	*2010*	*2010*	*2010*	*2010*
***Total Estimated Oil Saved by Existing and Proposed Projects** (Thousand Barrels)*	1,560	1,560	1,710	1,740	1,850	1,900	1,940	2,020	2,050	2,160	2,240
RPS Percent for Existing Projects	8.4%	8.3%	8.2%	8.1%	8.0%	7.9%	7.8%	7.8%	7.8%	7.8%	7.8%
RPS Percent for Proposed Projects	0.0%	0.0%	0.7%	0.8%	1.4%	1.6%	1.8%	2.1%	2.2%	2.7%	3.0%
RPS Percent Total:	**8.4%**	**8.3%**	**8.9%**	**8.9%**	**9.4%**	**9.5%**	**9.6%**	**9.9%**	**10.1%**	**10.5%**	**10.9%**
RPS Target:		8.0%					9.0%				

Footnotes:

1. Renewable energy projects listed have been proposed and meets the following:
   - Proposed Technology is currently in commercial operation in Hawaii or elsewhere
   - Renewable resource is available for the technology
   - Technology has established capital and operating costs.
2. Waste Gas electricity generation based upon a 90% capacity factor.
3. Estimated energy output is calculated by multiplying the probability of project completion in the year shown by the proposed output of the project.
4. Municipal Solid Waste electricity generation based upon a capacity factor of 65%.
5. A 35% Capacity factor was used for all future proposed windfarm projects due to:
   - Wind regime of proposed windfarm project location (class 6 or higher)
   - Size and type of wind turbines proposed
   - Review and averaging of the various capacity factors for windfarms
6. Kamaoa Repower GWh output shown in the table is calculated by subtracting the estimated output of the repowered windfarm (20MW @ 35% capacity factor = 61.3 GWh) by the estimated output (12 GWh) of the existing windfarm.
7. HRD-2 Power Purchase Agreement signed on December 30, 2003 for an [illegible] the windfarm size from 8 wind turbines (5.3 MW) to 16 wind turbines (10.56 MW).
8. Details of this project are still being developed and are not available at this time.
9. PGV has proposed to increase the output of their existing generation facility by 8MW. Well problems experienced in 2002 has put this proposal on hold.
10. PGV has proposed to expand the capacity of their facility to 60MW. This is a 22MW increment in addition to the 8MW increment for a total of 60MW.
11. Energy shown at 50% and 70% capacity factor to enable consideration that additional energy from PGV is constrained by system minimum load and transmission line capacity.
12. Kaheawa windfarm is assumed to have 27-660 kw wind turbines with a capacity factor of 35% (capacity factor per Zond Pacific's EIS).

4.3 Discussion of current situation and projections

Although the 2003 percentage of 8.40% exceeds the RPS goal of 7% for 2003, it should be noted this level might be difficult to maintain. Even if the amount of renewable energy remains at 2003 levels in future years (not at all a certainty as the problems experienced in 2002 drove home), the RPS percentage may decline because electric sales (the denominator in the calculation) continue to increase as the economy grows (see Figure 3). In fact, recent news of increased economic activities including increased military activities, such as the addition of a Stryker brigade and C-17 squadron, could result in even higher sales than currently forecast for Oahu. The point is simply that Hawaii's use of electricity is growing and therefore renewable production must grow or the RPS numbers will slip.

The calculations in Figure 4 indicate that given preliminary assumptions about the timeframe for completion of proposed projects, the amount of renewable energy on the system is expected to increase through 2010. Given the current forecast, we can hopefully meet or slightly exceed the 8% RPS level in 2005. With some fairly optimistic assumptions about specific future renewable energy projects, it also appears possible to meet or slightly exceed the 9% RPS in 2010.

Though we are committed to doing everything we can to achieve these preliminary projections, they are provided with the strong caveat that there are many variables impacting the actual development of renewable projects. For example, a renewable energy developer may be unable to obtain State or County permits, land lease, project financing, or community support. In addition, the developer may not be able to locate the renewable resource, or once operational, may be unable to keep its facility operating. Also it is

- Poor economics or inability to secure project financing (40 MW OTEC on Oahu, sugar mills on Hawaii, Maui, Oahu and Kauai, 9 MW wind on Oahu, 2 MW wind on Big Island);
- Community opposition (6 MW hydroelectric on Kauai, 2-4 MW hydroelectric on Maui, 14 MW hydroelectric on Hawaii, and hydroelectric on Molokai, 1 MW wind on Oahu);
- Unavailability of renewable resources (early geothermal projects on Hawaii, 4 MW biomass on Molokai); and
- Operational problems (1 MW wind on Molokai).

In addition, planning for a major wind project on the Big Island was significantly delayed because the potential developer was an Enron subsidiary at a time when Enron was distracted by its own corporate difficulties.

Any one of these factors, which are outside of the utilities' direct control, could prevent, delay or shut down a renewable energy project.

5.0 HECO Utilities' RPS Strategy

Despite these challenges, the HECO utilities take the RPS law very seriously and have demonstrated through our actions a strong commitment to achieving these levels.

As discussed in the previous Policy Statement, HECO utilities are executing a strategy that incorporates myriad activities, but which can be grouped into two main thrusts to increase its renewable energy portfolio:

(1) Pursue commercial renewable energy projects; and

(2) Accelerate the development of emerging renewable energy technologies that have potential for commercial application.

This strategy aims to pursue commercially available renewable energy generation in the near term, and in parallel, invest in research, development, and demonstration projects (RD&D) for emerging technologies and resources that are not currently commercially available or economically viable in the near term. This strategy will ensure that the HECO utilities are not only taking action to use as much renewable energy as is commercially and economically viable today, but also are helping to develop future sources of renewable energy. .

HECO's activities and initiates are described in detail below.

5.1 Pursue Commercial Renewable Energy Projects

The HECO utilities are pursuing commercial renewable energy projects by (1) keeping existing commercial renewable energy projects operating, and (2) pursuing new commercial renewable energy projects.

Keep Existing Commercial Renewable Energy Projects and Resources on the System

A key component of the HECO utilities' renewable portfolio strategy is to maintain the existing sources that are currently contributing renewable energy to the State's energy mix.

- Puueo Hydro Rehabilitation
  The existing 1.5 MW HELCO-owned run-of-river Puueo hydroelectric plant will be rehabilitated. The PUC approved HELCO's plans to rehabilitate the damaged generator by installing a modern, more efficient turbine generator with a capacity of roughly 2.28 to 2.4 MW.

- Lalamilo Windfarm
  The Lalamilo wind farm is an existing 2.28 MW HELCO-owned facility located in the Waimea area (Big Island). HELCO is presently considering options for increasing the output of this facility.

- PGV
  Due to well problems, the normal capacity of 30 MW at PGV had been reduced to an average of 5.6 MW from April to December 2002. PGV has drilled a new source well and converted KS-11 into a re-injection well, which has enabled PGV's output to slowly increase. PGV indicates that as of January 2004, it has been able to export roughly to 27 MW on a consistent basis.

- Hawaiian Commercial and Sugar Company (HC&S)
  MECO and Hawaiian Commercial and Sugar Company (HC&S) have agreed to have their power purchase agreement remain in effect at least through December 31, 2007, thus continuing the export of bagasse-generated and hydroelectric energy to the grid.

- Continue Existing DSM Programs
  Since its beginnings in 1996, our residential solar water heating program, the largest in the nation, has paid over $24 million in rebates to help 23,000 Hawaii households install solar. Over 4,700 Hawaii businesses have received an additional $18 million to help pay for energy efficient technologies such as lighting, cooling, heating and motors.

  In their second Integrated Resource Plan reports, HECO, HELCO and MECO all determined that their demand-side management (DSM) programs, including solar water heating and heat pumps, should continue to be included in future resource plans. Future rebates for solar water heating systems will provide an important incentive to encourage the adoption of solar water heating in the future. The HECO utilities continue to work towards obtaining PUC approval to continue, and expand, its DSM programs in the future.

  In addition to utility planning efforts, the 2003 Legislature demonstrated vision and commitment to renewable energy by passing the Renewable Energy Tax Credit. This legislation in conjunction with the utility demand-side management programs provides a positive incentive for both solar water heating and other renewable technologies.

Pursue and Facilitate New Commercial Renewable Energy Projects

HECO utilities are also pursuing programs to facilitate the commercial development of wind and biomass resources, as well as a program to enhance the positive integration of renewable energy systems with the electric grid.

Stimulate Renewable Energy Market

HECO formed a non-regulated subsidiary in December 2002 called Renewable Hawaii, Inc. to seek passive investment (providing a reasonable return) opportunities in cost-effective, commercial renewable energy projects in the State. With initial approval to invest up to $10 million, Renewable Hawaii's formation builds on HECO's ongoing commitment to increase Hawaii's use of renewable energy. The primary objectives of Renewable Hawaii are to stimulate the addition of cost-effective, commercial renewable energy in Hawaii, promote viable projects that will integrate positively with the utility grid and encourage renewable energy generation activity where such is lacking in targeted categories. (Technologies requiring research and design, prototype development, or demonstration will not be considered.)

Renewable Hawaii is attempting to stimulate the renewable energy market by releasing a series of island-specific Renewable Energy Request for Project Proposals (RE RFPP). The following summarizes the efforts thus far:

- *Island of Oahu*
  A RE RFPP for the island of Oahu was released on May 22, 2003 and closed on August 22, 2003. Eight proposals were received with three proposals passing the screening process and currently undergoing detailed evaluation.

- *Maui County (islands of Maui, Molokai, and Lanai)*
  A RE RFPP for the islands of Maui, Molokai, and Lanai was released on September 4, 2003 and closed on December 4, 2003. Five proposals were received; three proposals passed the screening process and are currently undergoing detailed evaluation.

- *Big Island of Hawaii*
  A RE RFPP for the Big Island of Hawaii was released on January 22, 2004. Proposals are due April 22, 2004.

Wind Program

Wind has a high potential for near-term commercial development because of the potential resource availability in Hawaii and the maturity of the technology. HECO has launched various wind initiatives:

- *High Resolution Wind Resource Maps*
  A new project funded by HECO, the Department of Business, Economic Development and Tourism (DBEDT), and the Department of Energy's National Renewable Energy Laboratory (NREL) has been initiated to update the State's wind resource maps. Preliminary high resolution wind resource maps, which graphically show wind power densities and wind speed, for the islands of Oahu, Big Island of Hawaii, Maui, Molokai, and Lanai have been developed to help identify new wind sites that could lead to commercial wind development.

- *Commercial Wind Assessment*
  In response to the findings of the high resolution wind resource maps, HECO will pursue site-specific assessments for wind farm development to investigate commercial development opportunities.

- *Offshore Wind Assessment*
  In anticipation of the findings of the high resolution wind resource maps, HECO hoped to conduct an assessment of potential offshore wind development on Oahu. However, the wind maps revealed that the offshore wind speeds were too low in areas having shallow depths (50 to 100 feet depth necessary for offshore wind development) and that the depths were too deep in areas having high wind speeds. Therefore, a study was not pursued.

- *Hawaii Wind Working Group*
  HECO and DBEDT co-chair the federal-sponsored Hawaii Wind Working Group (HWWG) as part of the Department of Energy's Wind Powering America program. The function of the HWWG is to provide a forum for information exchange among member organizations, the public, and decision makers and to encourage the development of technically and economically feasible wind projects. Formed in 2002, the HWWG has already had several meetings to exchange information.

Bioenergy Program

Biomass has a high potential for near-term commercial development because of the potential resource availability in Hawaii and the maturity of the technology. Initiatives to explore agricultural wastes and biofuels are underway.

- *Hawaii Biomass Program*
  HECO is working with HC&S and the University of Hawaii at Manoa (UHM) to develop the Hawaii Biomass Program. This proposed multi-year program would take a collaborative approach in developing a policy and technology framework that would lead to commercialization of an economically viable way to make full use of the total sugarcane material (including the use of cane trash) as a biomass energy resource (i.e., implement a dual-use crop strategy to economically produce both sugar and energy).

- *Biofuels Program*
  The potential utilization of biofuels (e.g., biodiesel, ethanol, and biofuel blends) in existing and new power generation units is being explored under HECO's Biofuels Program. The use of biofuels in electric power generating units represents a potential near-term renewable energy option. Before biofuels can be used on a commercial basis, however, the technical feasibility of firing stationary power generating units will need to be evaluated and demonstrated. Program activities include the following:

  - HECO is funding a project to obtain information on biofuel properties, supply, availability, and pricing (Phase 1 of a planned multi-phase, multi-year biofuels assessment study).
  - HECO is examining the feasibility of using boiler-grade fuel derived from used grease trap oil (such as the waste oil produced by restaurants) in its generating units.
  - MECO is evaluating the use of biodiesel during start-up operations in two of its generating units at Maalaea.
  - After a one-year pilot program, HECO has converted its entire fleet of diesel-fueled trucks and associated refueling stations to use B20 fuel (20% biodiesel and 80% diesel).

Facilitate Non-Utility Projects

HECO, HELCO and MECO receive and evaluate proposals from independent power producers seeking to sell power to the utilities. The following projects are either under review, in negotiations, or in the case of the Hawi project, completed with negotiations.

- *Union Mill Hydroelectric Project (HELCO)*
  Power Tech Industries, Inc. is proposing an 800 kW hydroelectric facility (Union Mill) located at Hawi, Hawaii.

- *Tradewinds (HELCO)*
  Tradewinds, LLC has proposed to build and operate a wood processing plant to process eucalyptus trees into various wood products. The plant would include a cogeneration facility to generate electricity fueled by wood waste with the excess electricity to be utilized on the HELCO grid. Tradewinds continues to pursue this project and HELCO has been in discussions with Tradewinds on the possible forms that this project could take.

- *Apollo (HELCO)*
  Apollo Energy Corporation (Apollo) is proposing to repower its existing 7,000 kW wind farm (Kamao'a Wind Farm) located at South Point, Hawaii. Under the plans, the repowered wind farm would increase in size to 20,500 kW. There is an agreement in principle between Apollo and HELCO on almost all of the key issues in a power purchase agreement (PPA).

- *Hawi (HELCO)*
  Hawi Renewable Development LLC (HRD) and HELCO signed a power purchase agreement (PPA) on December 30, 2003 for as-available energy from a 10,560 kW wind farm at Hawi,

Hawaii. The PUC approved a signed PPA between HELCO and Hawi Renewable Development, Inc. (HRD Inc.) for as-available energy from a 5,280 kW wind farm at Hawi, Hawaii. However, HRD Inc. decided to proceed negotiate for and upon, PUC approval, construct and operate a 10,560 kW wind farm, which would incorporate the original 5,280 kW wind farm at the same site.

- *GE Wind Energy/HRD Kaheawa Wind farm (MECO)*
  GE Wind Energy/HRD has proposed to develop a 20 MW wind farm on conservation land at Kaheawa Pastures, Maui. The Board of Land and Natural Resources decided to award a land lease for the site to GE Wind Energy/HRD, thus rendering a competing proposal moot. The current proposal is for a 17.8 MW wind farm at the site.

- *Sea Solar Power (HECO)*
  Sea Solar Power, International, LLC (SSPI) is proposing a 100 MW ocean thermal energy conversion (OTEC) facility to be anchored off Kahe Point, Oahu. The proposal received in late December 2003 proposes a July 2008 in-service date. If the project proves to be technically and economically feasible, the facility would be the first commercial OTEC facility in the world. HECO and SSPI are at the preliminary stages of discussions.

- *H-Power Expansion (HECO)*
  There have been informal, verbal comments by H-Power personnel that the City & County of Honolulu may want to expand the facility by adding a third boiler.

- *Makila Hydro (MECO)*
  Hawaii Energy Group, the consultant to the owner of Makila Hydro, is requesting an "as available" power purchase contract, for the proposed repowering of an existing 500 kW hydro generator located above Lahaina (previously interconnected to Pioneer Mill).

Streamlined Power Purchase and Net Energy Metering Agreements

In response to the passage of Act 272, HECO utilities worked hard to be ready for implementation of the new law before the Governor signed Act 272 into law on June 25, 2001. This allowed the utilities to implement the customer billing modification, a streamlined NEM Agreement, and a NEM Tariff on the same day the legislation was signed into law. This streamlined net energy metering process, coupled to the existing power purchase contract governing systems less than 10 kW (referred to as the PV-10 contract), creates an environment that encourages the operationally-positive integration of customer-sited NEM systems.

Standardized Interconnection Agreement

H.C.R. No. 172, H.D. 1 of the Twenty-Second State Legislature, dated April 1, 2003, directed the Consumer Advocate (CA) "to form an ad hoc advisory group to investigate and make recommendations regarding the implementation of standard offer contracts and standardized interconnection agreements to facilitate the purchase of electricity from renewable energy producers in Hawaii." HECO is part of the ad hoc advisory group. The Consumer Advocate submitted an interim report of the ah hoc advisory group to the Legislature in December 2003.

Renewable Energy Integration Program

The intermittent and variable nature of wind can put a major strain on the existing utility systems in terms of being able to control system frequency and power fluctuations, which can impact the reliability of power provided to customers. The smaller the system, the greater the impact these fluctuations may have on utility and consumer electrical equipment. HECO, HELCO, and MECO are conducting various projects to address this issue with the ultimate goal of allowing more wind on the utility systems.

- *Electronic Shock Absorber*
  To help stabilize operation of grid-connected wind turbines and minimize power fluctuations on an electric grid which is connected to a number of wind farms, HECO, HELCO, and MECO have teamed with a private company to conduct a study and confirm that a device can be developed from commercial products for installation between a wind farm and the utility grid. The purpose of the device, called the Electronic Shock Absorber (ESA), is to help the electric utility ride through short [redacted]

5.2 *Accelerate the development of emerging renewable energy technologies*

As part of HECO utilities' strategy to increase the renewable portfolio in the long-term, the companies are pursuing a broad range of initiatives to facilitate and accelerate the development of emerging renewable energy technologies in Hawaii.

HECO's parent company, Hawaiian Electric Industries (HEI), also provides venture capital funding to local companies engaged in emerging technology development to help accelerate technology deployment in Hawaii. HEI is involved with two companies developing renewable energy technology.

Hoku Scientific
In June 2002, HEI provided venture capital funding to Hoku Scientific, Inc., a Hawaii-based fuel cell R&D company that is developing proprietary fuel cell membrane technology. HEI's investment, which was part of a $1+ million round of funding, is viewed as critical to the further development of Hoku Scientific and its technology.

Worldwide Energy Group
HEI provided venture capital funding to Worldwide Energy Group, Inc., a Hawaii-based company developing a technology that converts sugarcane bagasse or other biomass resources into ethanol. Ethanol is a potential alternative fuel produced from locally available renewable sources that can be used to generate electricity.

Research, development and demonstration (RD&D) projects and projects that enhance public education about renewable energy are underway. HECO utilities' membership with the Electric Power Research Institute (EPRI), the research arm of the electric utility industry, keeps HECO utilities abreast of technology advances and is a core component of their RD&D thrust. In addition, HECO utilities will continue to seek partnerships with Federal, State, and County governments, the University of Hawaii, and other entities to increase their renewable energy portfolio.

RD&D projects, listed by technology, are described below.

Hydrogen and Fuel Cells

Hawaii Fuel Cell Test Facility

HECO has partnered with HNEI, U.S. Department of Defense (DOD), and UTC Fuel Cells to build and operate a hydrogen fuel cell test facility in Hawaii. The Hawaii Fuel Cell Test Facility, operational since April 2003, is housed in approximately 4,000 square feet of warehouse space at HECO's Ward Avenue facility and is used to evaluate the performance and reliability of production-sized, single-celled, fuel cell stack designs, materials, and fuels.

Hydrogen Power Park Study

HECO and HELCO are partnering with the DBEDT, HNEI, Sentech, Sunline, Stuart Energy, and UTC Fuel Cells in a project to introduce and demonstrate hydrogen-based infrastructure in Hawaii.

NELHA Gateway Project

HELCO is partnering with the Natural Energy Laboratory of Hawaii Authority (NELHA), DBEDT, HNEI, and Sentech in a project to construct distributed energy systems at the Gateway Center located at the entrance to NELHA's Hawaii Ocean Science and Technology (HOST) Park. This project aims to demonstrate renewable distributed energy resources and technology.

Solar

PV/Hydrogen project at Ford Island

A partnership between HECO, HNEI, Office of Naval Research (ONR), and Navy Region Hawaii was formed to develop a photovoltaic energy park (PVEP) on Navy land to generate electricity from the sun and conduct research and development related to renewable energy, hydrogen, and fuel cells. Congressional authorization and appropriation for federal funding for a utility-scale photovoltaic system and associated research and development are in place.

Solar Roof Assessment Study

HECO provided seed funds for a research effort by the University of Hawaii School of Architecture to develop a method for assessing the potential for solar power on roofs of existing buildings on the island of Oahu.

Kona Base Yard Grid-Connect Photovoltaic System

To demonstrate a net energy metered photovoltaic system that would be similar to what a small commercial or residential customer might consider, HELCO has installed a 5.4 kW photovoltaic system along with battery back-up and an educational display at its Kona base yard.

Solar Thermal/Cooling Pilot Project

HELCO is partnering with Pacific Energy Services, Solel, and the Outrigger Waikoloa Beach Marriott on a project to demonstrate a solar thermal pilot system. The pilot system, operational since April 2003, utilizes a solar panel to produce domestic hot water to help meet hotel hot water needs.

Maui Building-Integrated Photovoltaics

MECO provided a solar roof to the County of Maui's Lahaina Civic Center in November 2003. The roof serves the dual purpose of covering a walkway and providing the solar power for an electronic sign as well as parking lot lighting.

U.S. Department of Defense Bus Stop Photovoltaic Lighting Demonstration

To promote and demonstrate off-grid photovoltaic technology, HECO is working with the Army to install photovoltaic area lighting systems at existing bus stops and other facilities on military property (Schofield Barracks).

HELCO Photovoltaic Area Lighting Projects

To promote the use of off-grid photovoltaic applications, HELCO has partnered with various entities to install photovoltaic area lighting systems:

- HELCO, the County of Hawaii, and the U.S. Department of Energy Million Solar Roofs (MSR) program teamed up to design and install a solar lighted educational kiosk and solar lighting for the Hilo bay front public restrooms.

- Two solar-powered lights provide dusk-to-dawn security and improve the safety of the parking lot at the Catholic Charities Community and Immigrant Services transitional shelter Ka Hale `O Kawaihae.

- A partnership between HELCO and the County of Hawaii was formed to provide improved lighting for two County parks located in Puna (Ahalanui Beach Park and Pohoiki Beach Park).

Hydroelectric Resources

County of Hawaii In-line Hydroelectric Demonstration Project

HELCO has committed funding to cost-share with the County of Hawaii Department of Water Supply for an in-line hydroelectric generator project.

Lanai In-line Hydroelectric Study

MECO is working with Castle & Cooke Resorts to initiate a feasibility study to examine whether an in-line hydroelectric system can be installed in the existing distribution water pipelines from central Lanai to its Manele Bay Resort.

Ocean Resources

Navy Wave Energy Demonstration

Under a DOD Small Business Innovation Research (SBIR) grant, the Navy is partnering with Ocean Power Technologies (OPT) to assess the technical and economic feasibility of ocean wave energy. An at-sea demonstration of a 20-kW buoy wave energy system will be conducted at Kaneohe Marine Base. HECO provided engineering support regarding interconnecting to the electric grid and also serves as the Navy's technical advisor.

EPRI Offshore Wave Energy Project

HECO and DBEDT are participating in a multi-phase, multi-state collaborative project headed by EPRI to demonstrate the feasibility of wave power. The project will yield a conceptual design, including performance and cost estimates, for an offshore wave power device at a target location in each of six states (Hawaii, Maine, Massachusetts, California, Oregon, and Washington). Environmental and permitting issues will also be assessed.

Honolulu Board of Water Supply (BWS) Deep Ocean Water Application Facility Study

The BWS is evaluating the feasibility of developing a deep ocean water facility to produce potable water, generate power via OTEC, and provide chilled water for air conditioning and other applications. HECO is serving on the study's advisory group.

Public Education

Sun Power for Schools Program

HECO, HELCO, and MECO are entering the 8th year of their Sun Power for Schools program with the State of Hawaii Department of Education. Through the Sun Power for Schools program, HECO utilities will continue to install photovoltaic systems at Hawaii public schools using voluntary customer contributions and by providing in-kind utility contributions, including engineering, project management, administration, advertising, and marketing. To date, nineteen public schools have received photovoltaic systems (nine on Oahu, four on the Big Island, and six in Maui County).

HECO and the State of Hawaii Department of Education developed educational materials through a grant from the U.S Department of Energy's Million Solar Roofs program. The material was provided to public high school teachers. HECO, HELCO and MECO also conducted workshops for public high school and middle school teachers and participated in their Solar Sprint program where students evaluate their solar cars in field tests.

Bishop Museum Energy Pavilion

Increasing public education and awareness of renewable energy technology is an important step towards establishing a sustainable market for renewable energy. HECO provided funding for a grid-connected photovoltaic system and renewable energy exhibit located at Bishop Museum. The photovoltaic energy system and exhibit, called Hale Ikehu, is operational and open to the public. Visitors are able to observe a working photovoltaic system and learn about solar energy and other renewable energy technologies. During the first seven months, over 600 individuals directly participated in the Hale Ikehu educational programs and over 110,000 visitors to Bishop Museum had the opportunity to view the renewable energy displays and educational materials.

HECO Renewable Energy Website

More information about the HECO Utilities' renewable energy programs and initiatives can be found on HECO's website at www.heco.com under "Renewable Energy".

5.3 Additional Activities

Expand solar water heating and heat pump DSM programs

City and County of Honolulu Solar Roofs, Low-Income Solar Loan Program

To increase participation in HECO's Residential Efficient Water Heating Program, HECO entered into a partnership with the City and County of Honolulu to offer loans for the installation of solar water heating systems to low to moderate-income customers. Working with the Rehabilitation Loan Branch of the Department of Community Services has enabled HECO to offer these low-interest loans with a minimal amount of additional cost to the program.

The interest rate from the loan repayment is either 0% or 2% based on the applicant's income. The term of the loan is 7 years and generally gives customers monthly payments equal to or only slightly greater than the energy savings on their electric bill resulting from the installation of the solar system.

The loan program was introduced in April 2003 and as of December resulted in 35 approved loans.

Maui Solar Roofs Initiative

In September 2002, MECO formed a partnership with the County of Maui to increase the use of renewable energy in Maui County by increasing the number of solar water heating systems installed in residences. The County provided a grant in the amount of $250,000 to MECO to establish a revolving fund, administered by MECO, offering zero-interest loans to qualified homeowners. The loan would help finance the up front costs of installing a solar water heater on their home.

The fund is rebuilt as the approved applicants repay their loans. During the first year, 116 applications were approved of which 40% of the applicants were below the median income. Based on the program's success after its first year, MECO received an additional $100,000 grant from the County's Office of Economic Development. The program was modified to reserve at least 50% of the funds for applicants with household income below the median with priority going to low-income applicants.

MECO is in discussion with Maui County's Department of Housing and Human Concerns, Housing and Urban Development ("HUD") Section 8 administration, to expand the reach into the low-income rental market.

USDA Rural Utilities Service's Grant to Fund Maui Electric's Solar for Molokai Project

To further help make solar water heating more affordable for those who might not otherwise be able to invest in it, MECO has been selected to receive over $1.1 million in USDA funds for the installation of renewable energy solar water heating systems on the island of Molokai. MECO will provide about $400,000 in rebates, as well as project administration and outreach. Approved applicants will be required to attend classes to learn about basic solar system maintenance to ensure maximum performance over the life of the system and other energy saving techniques.

Community partners include the Department of Hawaiian Home Lands, Maui Economic Opportunity, Department of Housing and Human Concerns, Molokai Community Services Council, Office of Hawaiian Affairs, and Ke Aupuni Lokahi, which oversees the island's Enterprise Community efforts. The Energy, Resources and Technology Division of DBEDT will assist in conducting the educational classes.

Conclusion

HECO, HELCO and MECO are very pleased to have met the initial 7% target for 2003. Looking ahead, although preliminary projections are hopeful, given the variables which can impact potential renewable projects, we believe it is premature to draw definite conclusions about the achievability of the future goals of 8% in 2005 and 9% in 2010 or to set targets beyond 2010. But as is detailed in Section 5 of this report, despite the variables and challenges, we are actively working on many fronts to support and develop projects that will give us every opportunity to achieve these important goals for our State. What we most need is an equally strong commitment by the public sector to doing its part to help make the goals achievable.

CA-IR-283

[redacted] procurement?

b. Please describe the current state of the Company's system from the standpoint of power quality.

c. Where are power quality problems likely to develop over the period from 2005 through 2010?

d. What is HECO's target for system power quality over the period 2005 through 2010?

HECO Response:

a. Maintaining or improving system power quality is a consideration when procuring new power quality is subject to many uncertainties, including but not limited to (1) the actual load growth for each circuit, (2) equipment installed at customer facilities including induction motors, variable speed drives, distributed generators (DG), (3) instances of single and multiple generating unit outages, which may cause voltage and frequency disturbances on the system, (4) customer consumption patterns, and (5) projected distribution system circuit changes. Distribution system circuit changes may include (a) rebalancing of loads and redistribution of customers among circuits, and (b) replacement and upgrades of distribution transformers, protective relaying, and conductors. Without knowing this specific information, future power quality at specific locations is impossible to project. However, HECO has established transmission and distribution planning criteria to establish guidelines for planning a reliable transmission and distribution system, including maintaining proper voltage limits. Please see Docket No 03-0371 (Distributed Generation Docket), Direct Testimony of Shari Y. Ishikawa, HECO T-4, HECO-401 and HECO-404 filed with the Commission on July 14, 2004.

In addition, in the event intermittent generation (such as that from a wind farm) is connected to the system, that intermittent generation will be required to comply with performance standards with respect to power ramp rates and power fluctuation rates in order to maintain the power quality on the grid.

d. Please see response to CA-IR-283, parts b. and c. above.

CA-IR-284

a. Are there specific locations on the Company's system where service is, or is likely to become, sub-par in terms of power quality?

b. If so, where are those locations and what is the nature of the problem?

c. Please identify the measures by which the Company assesses local power quality.

d. Please identify the actual performance levels for each year beginning the year 2000 through 2004.

e. What is the projected change in power quality over the period 2005 through 2010?

f. Please identify the target level of power quality.

HECO Response:

a. No.

b. See response to part a. above.

c. HECO defines power quality as a measure of voltage variations and frequency variations at a customer's interconnection point over short- and long-term periods. As mentioned in response to CA-IR-283, part b., power quality is location specific. Each distribution circuit may be subject to different load levels and different load types (resistive, inductive or capacitive) that can affect the power quality of the circuit. However, HECO plans and operates its generation, transmission and distribution systems to maintain acceptable levels of power quality throughout the island. At a minimum, HECO's power quality must meet the requirements given in the PUC's General Order No. 7.

d. Voltage variations are location-specific and may be different at every customer interconnection point for each individual distribution circuit. Measurements of voltage variations at every customer interconnection point are not available.

e. Please see response to CA-IR-283, part c.

f. Please see response to CA-IR-283, part c.

CA-IR-285

Ref: HECO T-1, at 15.

Regarding the statement that the Company "works with customers and with leaders in federal, state, and county governments ... to plan and develop projects ... in a way that recognizes strong environmental ... values," please specify the Company's environmental goals and targets and compare the targets with federal and state standards.

HECO Response:

HECO's environmental goals and targets are to achieve total compliance with both federal and state environmental laws and regulations. HECO's Corporate Code of Conduct, Section XIII., Environmental, Health and Safety Matters states the following:

> "The Company is committed to protecting Hawaii's environment. In keeping with this commitment, the Company will consider health, safety, and the environment in its business decisions. You are expected to comply with all applicable environmental, health and safety laws and regulations."

CA-IR-286

a. Is limiting the use of potable water a goal of the Company resource procurement process? Explain why or why not.

b. Please identify the actual potable water consumption for the HECO system for each year beginning from the year 2000 through 2004.

c. What are the projected potable water consumption levels in each year during the period 2005 through 2010 with and without the resource additions proposed in the instant rate case?

d. Please identify the target for potable water consumption.

HECO Response:

a. Yes. HECO recognizes the value of potable water and the need to conserve it for human consumption. The generating resources in HECO's long-term resource plan will not depend on potable water for the electricity production process. Plans are to utilize brackish groundwater, which will be purified for use in the generating units.

b. The table below provides available information on potable water (metered City water) used by HECO power plants and certain HECO facilities. HECO does not have information on water used by Independent Power Producers.

	Power Plants[1]	**Offices**[2]	**Total**
2000	130,267,000	N/A	130,267,000
2001	112,296,000	N/A	112,296,000
2002	132,449,000	12,464,000	144,913,000
2003	96,621,000	10,323,000	106,944,000
2004	101,327,000	9,530,000	110,857,000

Note:
1. "Power Plants" include consumption from Honolulu Power Plant, Waiau Power Plant, Kahe Power Plant and Iwilei Tank Farm.
2. "Offices" included consumption from HECO's King Street and Ward Avenue offices, Archer Substation, and the Cooke Street Fuel Cell Facility.

c. HECO does not have this information.

d. HECO does not have specific targets for potable water consumption. HECO is well aware of the need to conserve potable water. HECO plans to use alternative water sources (such as purified brackish groundwater) whenever practical in the process to produce electricity at the power plants.

CA-IR-287

a. Is limiting impacts on the marine environment one of the criteria used by HECO for resource procurement?

b. If so, please specify the criterion and explain how it is applied in determining which resources to procure.

HECO Response:

a. Impacts on the marine environment are considered in the development of long-term resource plans in HECO's IRP process. Consideration is given to minimizing impacts on the marine environment as well as to meeting many other IRP objectives. Please refer to HECO's response to CA-IR-282, part b., for the IRP objectives and the attributes and measures considered. There are many trade-offs that need to be made among the competing objectives.

b. As stated in HECO's response to CA-IR-282, part b., seven broad categories of long-term [illegible]

January 30, 1998, in Docket No. 95-0347.) As part of the Externalities Workbook effort in HECO IRP-2, the externality impact for oil spills was monetized. The monetized externality value being used in HECO IRP-3 for the oil spill externality is $0.16 per barrel of oil (2003 dollars). The total oil spill externality cost for potential oil spills based on the total barrels of oil consumed in each plan is included as part of the total societal cost.

In each of the six candidate plans developed in HECO IRP-3, the measures for each attribute identified in CA-IR-282 were quantified to the extent possible. Comparisons were made across the six plans for each attribute to evaluate the extent to which each plan met the broader objectives. The measures were provided to the Advisory Group at the November 15, 2004 HECO IRP-3 Advisory Group meeting. The potential impact of various plans on the marine environment must be considered along with the other objectives and attributes in HECO IRP-3.

CA-IR-288

a. Is limiting impacts on the terrestrial environment one of the criteria used by HECO for resource procurement?

b. If so, please specify the criterion and explain how it is applied in determining which resources to procure.

c. Please provide any data or other measures that would provide a context within which to assess this criterion.

d. Please indicate how new transmission construction is assessed relative to this criterion. How are the terrestrial impacts of a transmission line evaluated relative to those of a generating facility?

HECO Response:

a. Impacts on the terrestrial environment are considered in the development of long-term resource plans in HECO's IRP process. Consideration is given to minimizing impacts on the terrestrial environment as well as to meeting many other IRP objectives. Please refer to HECO's response to CA-IR-282, part b., for the IRP objectives and the attributes and measures considered. There are many trade-offs that need to be made among the competing objectives.

b. As stated in HECO's response to CA-IR-282, part b., seven broad categories of long-term resource plan objectives were established HECO's IRP-3 process. Under each category, several attributes were identified and the attributes were quantified to the extent possible to serve as "measures of success" in meeting the broad objectives. The objectives and attributes were developed with HECO IRP Advisory Group input.

The potential impact to the terrestrial environment was considered under the category of Protect the Environment. Item (c) under that category provides qualitative assessments of each plan's potential impact to the terrestrial environment. Please refer to the attachment (on page 4) in HECO's response to CA-IR-282, part b.

The potential impact to the terrestrial environment was also considered under the category of Minimize Potential Societal and Cultural Impacts. See items (b) Compatibility with Community Lifestyles and Planning Processes and (c) Land Use. Item (b) is assessed qualitatively and item (c) is quantified in terms of the acreage that would be needed to accommodate all of the resources in the long-term plan. Please refer to the attachment (on page 6) in HECO's response to CA-IR-282, part b.

c. At the advice of the Integration Technical Committee members, the Potential for Impact to Terrestrial Environment was one attribute used to qualitatively assess each of the six plans. [redacted] impacts as a result of any new transmission construction identified. Land related issues for new transmission construction are very project-specific and must take into account detailed parameters such as a project's route and design. Such detailed attributes are better addressed in the project engineering and design process and more appropriately evaluated in the Environmental Impact Statement and not in the IRP process.

CA-IR-289

a. Is limiting CO2 emissions to the atmosphere one of the criteria used by HECO for resource [redacted]

b. If so, please specify the criterion and explain how it is applied in determining which resources to procure.

c. Please identify the actual CO2 emissions for the HECO system for each year 2000 through 2004.

d. What are the projected CO2 emissions levels in each year during the period 2005 through [redacted]

2010 with and without the resource additions proposed in the instant rate case?

e. Please identify the CO2 emissions target.

HECO Response:

a. HECO quantifies the amount of CO_2 emissions in its integrated resource planning process.

[redacted]

c. HECO objects to this question as it is not relevant to the instant rate case. However, without waiving its objection, please refer to the table below for PM10, SO_2, CO, NO_X, VOC and CO_2 emissions from HECO's Honolulu, Kahe and Waiau Power Plants for the period 2000 to 2003. HECO does not yet have 2004 data available. HECO also does not have emission data from the Independent Power Producers from which it purchases firm capacity and as-available energy.

CA-IR-289(c), 290(c), 291(c), 292(c), 293(c), 294(c)
Hawaiian Electric Company Annual Emissions
Prepared by HECO Environmental 2/25/2005

	2000 (Tons/yr)	2001 (Tons/yr)	2002 (Tons/yr)	2003 (Tons/yr)	2004 (Tons/yr)
PM10	778.0	763.7	905.4	1366.6	Data not available at this time
SO2	10236.6	10052.4	10102.0	10229.5	
CO	786.4	782.4	805.6	809.9	
NOx	8175.4	7052.5	7394.3	7428.5	
VOC	120.2	118.6	122.6	123.5	
	2000 (1,000 TPY)	2001 (1,000 TPY)	2002 (1,000 TPY)	2003 (1,000 TPY)	
CO2	4049.5	4033.6	4150.5	4178.0	

Notes: Annual emissions for PM10, SO2, CO, NOx, and VOC are summarized from Annual Emission Reports submitted to the Department of Health.

CO2 emissions are voluntarily reported to the Department of Energy on an annual basis as part of Climate Challenge program.

Includes Honolulu, Waiau, and Kahe Power Plants only.

d. HECO objects to this question as it is not relevant to the instant rate case. However, without waiving its objection, HECO provides the following response. In its HECO IRP-3 integration process, HECO estimated future CO_2 emissions for each of the six candidate plans developed with Advisory Group input. (Please refer to HECO's response to CA-IR-282, part b.) The table below provides the estimated CO_2 emissions for the period 2006 to 2010 for each of the six plans. Because the HECO IRP-3 planning period begins in 2006, HECO does not have an emission estimate for 2005.

Projected CO_2 Emissions (Tons) for HECO IRP-3 Candidate Plans
Utility and Non-Utility Units Combined

		Plan 1	Plan 2	Plan 3	Plan 4	Plan 5	Plan 6
	IRP-2 Evaluation Report with Utility CHP	Least Cost Plan	Meets the State RPS Law -- Oahu Only	Maximize Renewable Energy Plan	Meets the State RPS Law	Maximize Fuel Diversity Plan	Combination Plan
2006	7,813,902	7,694,397	7,694,397	7,694,397	7,694,397	7,756,601	7,694,397
2007	7,917,167	7,743,632	7,743,632	7,743,632	7,743,632	7,852,637	7,743,632
2008	7,990,696	7,757,937	7,757,937	7,751,022	7,757,937	7,919,873	7,757,937
2009	8,032,866	7,734,175	7,734,175	7,617,444	7,734,175	7,846,123	7,631,214
2010	8,138,427	7,763,398	7,763,308	7,626,100	7,763,398	7,930,109	7,659,567

The projected CO_2 emissions include those from existing HECO generating units and those estimated by HECO from firm capacity Independent Power Producer units, including AES Hawaii, Kalaeloa and H-Power. HECO does not have actual CO_2 emission rates from these firm capacity Independent Power Producer units. For IRP purposes, HECO used estimates of emissions rates for these types of units (atmospheric fluidized bed combustion coal-fired unit, low sulfur fuel oil-fired combined cycle unit, and municipal solid waste generating unit) based on Unit Information Forms provided by a consultant for HECO's IRP-2 supply-side resource option evaluation.

The simple cycle combustion turbine to be installed in 2009 may range in size from 75 MW to 120 MW, depending on which turbine vendor is selected through a competitive bidding process to provide the turbine. For IRP purposes, it is assumed that a 76 MW simple cycle unit is installed in 2009 in all candidate plans and is the basis for the emission calculations shown in the table above. The unit is needed sooner as HECO has an urgent need for capacity, but it cannot be installed sooner than 2009 due to the long lead times for permitting, equipment procurement and construction. The emission data in the table are based on the unit utilizing fuel with a sulfur content of 0.4% by weight. The type of fuel that will actually be used will be 0.35% sulfur diesel or 0.05% sulfur diesel or naphtha based on the air permit application for the unit. The 0.4% sulfur value was used for IRP purposes because it was the value available at the time the IRP database was being compiled. Only the emission rate for SO_2 is dependent upon the sulfur content of the fuel. In general, the emission rates for CO_2, VOC, PM10, NO_X and CO are not sensitive to any significant degree to whether diesel or naphtha is used. HECO does not have candidate plans or emission data for the scenario where the unit is not installed in 2009.

CA-IR-290

a. Is limiting VOC emissions to the atmosphere one of the criteria used by HECO for resource procurement?

b. If so, please specify the criterion and explain how it is applied in determining which resources to procure.

c. Please identify the actual VOC emissions for the HECO system for each year 2000 through 2004.

d. What are the projected VOC emissions levels in each year during the period 2005 through 2010 with and without the resource additions proposed in the instant rate case?

e. Please identify the VOC emissions target.

HECO Response:

a. HECO's and Independent Power Producers' (IPPs) generating units need to comply with the requirements of their respective Covered Source Permits (i.e., air permits), which set limits on emissions to the atmosphere. The Power Purchase Agreements between HECO and the IPPs contain provisions that require the IPPs to operate in compliance with their air permits. In addition, in the IRP process, consideration is given to air emissions remaining after the implementation of required emission controls.

In the IRP process, HECO quantifies the amount of VOC emissions in the candidate long-term resource plans. Consideration is given to reducing VOC emissions as well as to meeting many other IRP objectives. Please refer to HECO's response to CA-IR-282, part b., for the IRP objectives and the attributes and measures considered. There are many trade-offs that need to be made among the competing objectives.

Externality impacts of emissions are also considered in the IRP process in the societal perspective. (Please refer to Section 10.5 of HECO's IRP-2 report, filed on January 30, 1998, in Docket No. 95-0347.) As part of the Externalities Workbook effort in

HECO IRP-2, the externality impacts for PM10, NO_X and SO_2 were monetized while those for VOC and CO could not be monetized.

b. No specific criterion is used to limit VOC emissions when developing long-term resource plans in the integrated resource planning process. Instead, the amounts of the various emissions (CO_2, VOC, CO, PM10, NO_X and SO_2) are quantified in each plan. In addition, many other attributes, such as costs, reliability, fuel consumption, and system efficiency, of each plan are also quantified. Furthermore, certain attributes, such as impacts on social practices within various cultures, cannot be quantified and are qualitatively assessed. Comparisons of all of these attributes were made across the six candidate plans in HECO [redacted] the attributes and measures considered.

c. HECO objects to this question as it is not relevant to the instant rate case. However, without waiving its objection, HECO has provided the requested information in response to CA-IR-

Projected VOC Emissions (Tons) for HECO IRP-3 Candidate Plans
Utility and Non-Utility Units Combined

		Plan 1	Plan 2	Plan 3	Plan 4	Plan 5	Plan 6
	IRP-2 Evaluation Report with Utility CHP	Least Cost Plan	Meets the State RPS Law -- Oahu Only	Maximize Renewable Energy Plan	Meets the State RPS Law	Maximize Fuel Diversity Plan	Combination Plan
2006	379	381	381	381	381	370	381
2007	386	393	393	393	393	374	393
2008	397	409	409	409	409	380	409
2009	536	414	414	410	414	372	411
2010	623	436	436	431	436	385	432

The projected VOC emissions include those from existing HECO generating units and those estimated by HECO from firm capacity Independent Power Producer units, including AES Hawaii, Kalaeloa and H-Power. HECO does not have actual VOC emission rates from these firm capacity Independent Power Producer units. For IRP purposes, HECO used estimates of emissions rates for these types of units (atmospheric fluidized bed combustion coal-fired unit, low sulfur fuel oil-fired combined cycle unit, and municipal solid waste generating unit) based on Unit Information Forms provided by a consultant for HECO's IRP-2 supply-side resource option evaluation.

The simple cycle combustion turbine to be installed in 2009 may range in size from 75 MW to 120 MW, depending on which turbine vendor is selected through a competitive bidding process to provide the turbine. For IRP purposes, it is assumed that a 76 MW simple cycle unit is installed in 2009 in all candidate plans and is the basis for the emission

calculations shown in the table above. The unit is needed sooner as HECO has an urgent

CA-IR-291

a. Is limiting CO emissions to the atmosphere one of the criteria used by HECO for resource procurement?

b. If so, please specify the criterion and explain how it is applied in determining which resources to procure.

c. Please identify the actual CO emissions for the HECO system for each year 2000 through 2004.

d. What are the projected CO emissions levels in each year during the period 2005 through 2010 with and without the resource additions proposed in the instant rate case?

e. Please identify the CO emissions target.

HECO Response:

a. HECO's and Independent Power Producers' (IPPs) generating units need to comply with the requirements of their respective Covered Source Permits (i.e., air permits), which set limits on emissions to the atmosphere. The Power Purchase Agreements between HECO and the IPPs contain provisions that require the IPPs to operate in compliance with their air permits. In addition, in the IRP process, consideration is given to air emissions remaining after the implementation of required emission controls.

In the IRP process, HECO quantifies the amount of CO emissions in the candidate long-term resource plans. Consideration is given to reducing CO emissions as well as to meeting many other IRP objectives. Please refer to HECO's response to CA-IR-282, part b., for the IRP objectives and the attributes and measures considered. There are many trade-offs that need to be made among the competing objectives.

Externality impacts of emissions are also considered in the IRP process in the societal

HECO IRP-2, the externality impacts for PM10, NO_X and SO_2 were monetized while those for VOC and CO could not be monetized.

b. No specific criterion is used to limit CO emissions when developing long-term resource plans in the integrated resource planning process. Instead, the amounts of the various emissions (CO_2, VOC, CO, PM10, NO_X and SO_2) are quantified in each plan. In addition, many other attributes, such as costs, reliability, fuel consumption, and system efficiency, of each plan are also quantified. Furthermore, certain attributes, such as impacts on social practices within various cultures, cannot be quantified and are qualitatively assessed. Comparisons of all of these attributes were made across the six candidate plans in HECO IRP-3. Please refer to HECO's response to CA-IR-282, part b., for the IRP objectives and the attributes and measures considered.

c. HECO objects to this question as it is not relevant to the instant rate case. However, without waiving its objection, HECO has provided the requested information in response to CA-IR-289, part c.

d. HECO objects to this question as it is not relevant to the instant rate case. However, without waiving its objection, HECO provides the following response. In its HECO IRP-3 integration process, HECO estimated future CO emissions for each of the six candidate plans developed with Advisory Group input. (Please refer to HECO's response to CA-IR-282, part b.) The table below provides the estimated CO emissions for the period 2006 to 2010 for each of the six plans. Because the HECO IRP-3 planning period begins in 2006, HECO does not have an emission estimate for 2005.

Projected CO Emissions (Tons) for HECO IRP-3 Candidate Plans
Utility and Non-Utility Units Combined

		Plan 1	Plan 2	Plan 3	Plan 4	Plan 5	Plan 6
	IRP-2 Evaluation Report with Utility CHP	Least Cost Plan	Meets the State RPS Law -- Oahu Only	Maximize Renewable Energy Plan	Meets the State RPS Law	Maximize Fuel Diversity Plan	Combination Plan
2006	2,140	2,139	2,139	2,139	2,139	2,096	2,139
2007	2,174	2,184	2,184	2,184	2,184	2,108	2,184
2008	2,223	2,250	2,250	2,249	2,250	2,138	2,250
2009	2,497	2,261	2,261	2,240	2,261	2,097	2,243
2010	2,716	2,359	2,359	2,332	2,359	2,163	2,340

The projected CO emissions include those from existing HECO generating units and those estimated by HECO from firm capacity Independent Power Producer units, including AES Hawaii, Kalaeloa and H-Power. HECO does not have actual CO emission rates from these firm capacity Independent Power Producer units. For IRP purposes, HECO used estimates of emissions rates for these types of units (atmospheric fluidized bed combustion coal-fired unit, low sulfur fuel oil-fired combined cycle unit, and municipal solid waste generating unit) based on Unit Information Forms provided by a consultant for HECO's IRP-2 supply-side resource option evaluation.

The simple cycle combustion turbine to be installed in 2009 may range in size from 75 MW to 120 MW, depending on which turbine vendor is selected through a competitive bidding process to provide the turbine. For IRP purposes, it is assumed that a 76 MW simple cycle unit is installed in 2009 in all candidate plans and is the basis for the emission

calculations shown in the table above. The unit is needed sooner as HECO has an urgent need for capacity, but it cannot be installed sooner than 2009 due to the long lead times for permitting, equipment procurement and construction. The emission data in the table are based on the unit utilizing fuel with a sulfur content of 0.4% by weight. The type of fuel that will actually be used will be 0.35% sulfur diesel or 0.05% sulfur diesel or naphtha based on the air permit application for the unit. The 0.4% sulfur value was used for IRP purposes because it was the value available at the time the IRP database was being compiled. Only the emission rate for SO_2 is dependent upon the sulfur content of the fuel. In general, the emission rates for CO_2, VOC, PM10, NO_X and CO are not sensitive to any significant degree to whether diesel or naphtha is used. HECO does not have candidate plans or emission data for the scenario where the unit is not installed in 2009.

CA-IR-292

a. Is limiting PM10 emissions to the atmosphere one of the criteria used by HECO for resource procurement?

b. If so, please specify the criterion and explain how it is applied in determining which resources to procure.

c. Please identify the actual PM10 emissions for the HECO system for each year 2000 through 2005.

d. What are the projected PM10 emissions levels in each year during the period 2005 through 2010 with and without the resource additions proposed in the instant rate case?

e. Please identify the target for PM10 emissions.

HECO Response:

a. HECO's and Independent Power Producers' (IPPs) generating units need to comply with the requirements of their respective Covered Source Permits (i.e., air permits), which set limits on emissions to the atmosphere. The Power Purchase Agreements between HECO and the IPPs contain provisions that require the IPPs to operate in compliance with their air permits. In addition, in the IRP process, consideration is given to air emissions remaining after the implementation of required emission controls.

In the IRP process, HECO quantifies the amount of PM10 emissions in the candidate long-term resource plans. Consideration is given to reducing PM10 emissions as well as to meeting many other IRP objectives. Please refer to HECO's response to CA-IR-282, part b., for the IRP objectives and the attributes and measures considered. There are many trade-offs that need to be made among the competing objectives.

Externality impacts of emissions are also considered in the IRP process in the societal perspective. (Please refer to Section 10.5 of HECO's IRP-2 report, filed on

HECO IRP-2, the externality impacts for PM10, NO_X and SO_2 were monetized while those for VOC and CO could not be monetized. The monetized externality value being used in HECO IRP-3 for PM10 is $4,984 per ton (2003 dollars).

b. No specific criterion is used to limit PM10 emissions when developing long-term resource plans in the integrated resource planning process. Instead, the amounts of the various emissions (CO_2, VOC, CO, PM10, NO_X and SO_2) are quantified in each plan. In addition, many other attributes, such as costs, reliability, fuel consumption, and system efficiency, of each plan are also quantified. Furthermore, certain attributes, such as impacts on social practices within various cultures, cannot be quantified and are qualitatively assessed. Comparisons of all of these attributes were made across the six candidate plans in HECO IRP-3. Please refer to HECO's response to CA-IR-282, part b., for the IRP objectives and the attributes and measures considered.

c. HECO objects to this question as it is not relevant to the instant rate case. However, without waiving its objection, HECO has provided the requested information in response to CA-IR-289, part c.

d. HECO objects to this question as it is not relevant to the instant rate case. However, without waiving its objection, HECO provides the following response. In its HECO IRP-3 integration process, HECO estimated future PM10 emissions for each of the six candidate plans developed with Advisory Group input. (Please refer to HECO's response to CA-IR-282, part b.) The table below provides the estimated PM10 emissions for the period 2006 to 2010 for each of the six plans. Because the HECO IRP-3 planning period begins in 2006, HECO does not have an emission estimate for 2005.

Projected PM10 Emissions (Tons) for HECO IRP-3 Candidate Plans
Utility and Non-Utility Units Combined

		Plan 1	Plan 2	Plan 3	Plan 4	Plan 5	Plan 6
	IRP-2 Evaluation Report with Utility CHP	Least Cost Plan	Meets the State RPS Law -- Oahu Only	Maximize Renewable Energy Plan	Meets the State RPS Law	Maximize Fuel Diversity Plan	Combination Plan
2006	1,675	1,705	1,705	1,705	1,705	1,715	1,705
2007	1,702	1,723	1,723	1,723	1,723	1,740	1,723
2008	1,711	1,723	1,723	1,721	1,723	1,747	1,723
2009	1,741	1,741	1,741	1,716	1,741	1,750	1,719
2010	1,763	1,746	1,746	1,716	1,746	1,764	1,723

The projected PM10 emissions include those from existing HECO generating units and those estimated by HECO from firm capacity Independent Power Producer units, including AES Hawaii, Kalaeloa and H-Power. HECO does not have actual PM10 emission rates from these firm capacity Independent Power Producer units. For IRP purposes, HECO used estimates of emissions rates for these types of units (atmospheric fluidized bed combustion coal-fired unit, low sulfur fuel oil-fired combined cycle unit, and municipal solid waste generating unit) based on Unit Information Forms provided by a consultant for HECO's IRP-2 supply-side resource option evaluation.

The simple cycle combustion turbine to be installed in 2009 may range in size from 75 MW to 120 MW, depending on which turbine vendor is selected through a competitive bidding process to provide the turbine. For IRP purposes, it is assumed that a 76 MW simple cycle unit is installed in 2009 in all candidate plans and is the basis for the emission

calculations shown in the table above. The unit is needed sooner as HECO has an urgent need for capacity, but it cannot be installed sooner than 2009 due to the long lead times for permitting, equipment procurement and construction. The emission data in the table are based on the unit utilizing fuel with a sulfur content of 0.4% by weight. The type of fuel that will actually be used will be 0.35% sulfur diesel or 0.05% sulfur diesel or naphtha based on the air permit application for the unit. The 0.4% sulfur value was used for IRP purposes because it was the value available at the time the IRP database was being compiled. Only the emission rate for SO_2 is dependent upon the sulfur content of the fuel. In general, the emission rates for CO_2, VOC, PM10, NO_X and CO are not sensitive to any significant degree to whether diesel or naphtha is used. HECO does not have candidate plans or emission data for the scenario where the unit is not installed in 2009.

e. HECO does not have a specific emissions target. Consideration is given to reducing PM10 emissions as well as to meeting many other IRP objectives.

CA-IR-293

a. Is limiting NOx emissions to the atmosphere one of the criteria used by HECO for resource procurement?

b. If so, please specify the criterion and explain how it is applied in determining which resources to procure.

c. Please identify the actual NOx emissions for the HECO system for each year 2000 through 2005.

d. What are the projected NOx emissions levels in each year during the period 2005 through 2010 with and without the resource additions proposed in the instant rate case?

e. Please identify the target for NOx emissions.

HECO Response:

a. HECO's and Independent Power Producers' (IPPs) generating units need to comply with the requirements of their respective Covered Source Permits (i.e., air permits), which set limits on emissions to the atmosphere. The Power Purchase Agreements between HECO and the IPPs contain provisions that require the IPPs to operate in compliance with their air permits

HECO IRP-2, the externality impacts for PM10, NO_2 and SO_2 were monetized while those for VOC and CO could not be monetized. The monetized externality value being used in HECO IRP-3 for NO_X is $37.06 per ton (2003 dollars).

b. No specific criterion is used to limit NO_X emissions when developing long-term resource plans in the integrated resource planning process. Instead, the amounts of the various emissions (CO_2, VOC, CO, PM10, NO_X and SO_2) are quantified in each plan. In addition, many other attributes, such as costs, reliability, fuel consumption, and system efficiency, of each plan are also quantified. Furthermore, certain attributes, such as impacts on social practices within various cultures, cannot be quantified and are qualitatively assessed. Comparisons of all of these attributes were made across the six candidate plans in HECO IRP-3. Please refer to HECO's response to CA-IR-282, part b., for the IRP objectives and the attributes and measures considered.

c. HECO objects to this question as it is not relevant to the instant rate case. However, without waiving its objection, HECO has provided the requested information in response to CA-IR-289, part c.

d. HECO objects to this question as it is not relevant to the instant rate case. However, without waiving its objection, HECO provides the following response. In its HECO IRP-3 integration process, HECO estimated future NO_X emissions for each of the six candidate plans developed with Advisory Group input. (Please refer to HECO's response to CA-IR-282, part b.) The table below provides the estimated NO_X emissions for the period 2006 to 2010 for each of the six plans. Because the HECO IRP-3 planning period begins in 2006, HECO does not have an emission estimate for 2005.

Projected NO_X Emissions (Tons) for HECO IRP-3 Candidate Plans
Utility and Non-Utility Units Combined

		Plan 1	Plan 2	Plan 3	Plan 4	Plan 5	Plan 6
	IRP-2 Evaluation Report with Utility CHP	Least Cost Plan	Meets the State RPS Law -- Oahu Only	Maximize Renewable Energy Plan	Meets the State RPS Law	Maximize Fuel Diversity Plan	Combination Plan
2006	14,005	14,010	14,010	14,010	14,010	13,732	14,010
2007	14,401	14,484	14,484	14,484	14,484	13,992	14,484
2008	14,661	14,844	14,844	14,827	14,844	14,105	14,844
2009	15,194	15,485	15,485	15,230	15,485	14,262	15,262
2010	15,429	15,839	15,839	15,536	15,839	14,373	15,614

The projected NO_X emissions include those from existing HECO generating units and those estimated by HECO from firm capacity Independent Power Producer units, including AES Hawaii, Kalaeloa and H-Power. HECO does not have actual NO_X emission rates from these firm capacity Independent Power Producer units. For IRP purposes, HECO used estimates of emissions rates for these types of units (atmospheric fluidized bed combustion coal-fired unit, low sulfur fuel oil-fired combined cycle unit, and municipal solid waste generating unit) based on Unit Information Forms provided by a consultant for HECO's IRP-2 supply-side resource option evaluation.

The simple cycle combustion turbine to be installed in 2009 may range in size from 75 MW to 120 MW, depending on which turbine vendor is selected through a competitive bidding process to provide the turbine. For IRP purposes, it is assumed that a 76 MW simple cycle unit is installed in 2009 in all candidate plans and is the basis for the emission

calculations shown in the table above. The unit is needed sooner as HECO has an urgent need for capacity, but it cannot be installed sooner than 2009 due to the long lead times for permitting, equipment procurement and construction. The emission data in the table are based on the unit utilizing fuel with a sulfur content of 0.4% by weight. The type of fuel that will actually be used will be 0.35% sulfur diesel or 0.05% sulfur diesel or naphtha based on the air permit application for the unit. The 0.4% sulfur value was used for IRP purposes because it was the value available at the time the IRP database was being compiled. Only the emission rate for SO_2 is dependent upon the sulfur content of the fuel. In general, the emission rates for CO_2, VOC, PM10, NO_X and CO are not sensitive to any significant degree to whether diesel or naphtha is used. HECO does not have candidate plans or emission data for the scenario where the unit is not installed in 2009.

e. HECO does not have a specific emissions target. Consideration is given to reducing PM10 emissions as well as to meeting many other IRP objectives.

CA-IR-294

a. Is limiting SO2 emissions to the atmosphere one of the criteria used by HECO for resource procurement?

b. If so, please specify the criterion and explain how it is applied in determining which resources to procure.

c. Please identify the actual SO2 emissions for the HECO system for each year 2000 through 2005.

d. What are the projected SO2 emissions levels in each year during the period 2005 through 2010 with and without the resource additions proposed in the instant rate case?

e. Please identify the target for SO2 emissions.

HECO Response:

a. HECO's and Independent Power Producers' generating units need to comply with the requirements of their respective Covered Source Permits (i.e., air permits), which set limits on emissions to the atmosphere. The Power Purchase Agreements between HECO and the IPPs contain provisions that require the IPPs to operate in compliance with their air permits. In addition, in the IRP process, consideration is given to air emissions remaining after the implementation of required emission controls.

In the IRP process, HECO quantifies the amount of SO_2 emissions in the candidate long-term resource plans. Consideration is given to reducing SO_2 emissions as well as to meeting many other IRP objectives. Please refer to HECO's response to CA-IR-282, part b, for the IRP objectives and the attributes and measures considered. There are many trade-offs that need to be made among the competing objectives.

Externality impacts of emissions are also considered in the IRP process in the societal perspective. (Please refer to Section 10.5 of HECO's IRP-2 report, filed on January 30, 2, the externality impacts for PM10, NO_2 and SO_2 were monetized while those for VOC and CO could not be monetized. The monetized externality value being used in HECO IRP-3 for SO_2 is $51.56 per ton (2003 dollars).

b. No specific criterion is used to limit SO_2 emissions when developing long-term resource plans in the integrated resource planning process. Instead, the amounts of the various emissions (CO_2, VOC, CO, PM10, NO_X and SO_2) are quantified in each plan. In addition, many other attributes, such as costs, reliability, fuel consumption, and system efficiency, of each plan are also quantified. Furthermore, certain attributes, such as impacts on social practices within various cultures, cannot be quantified and are qualitatively assessed. Comparisons of all of these attributes were made across the six candidate plans in HECO IRP-3. Please refer to HECO's response to CA-IR-282, part b, for the IRP objectives and the attributes and measures considered.

c. HECO objects to this question as it is not relevant to the instant rate case. However, without waiving its objection, HECO has provided the requested information in response to CA-IR-289, part c.

d. HECO objects to this question as it is not relevant to the instant rate case. However, without waiving its objection, HECO provides the following response. In its HECO IRP-3 integration process, HECO estimated future NO_X emissions for each of the six candidate plans developed with Advisory Group input. (Please refer to HECO's response to CA-IR-282, part b.) The table below provides the estimated NO_X emissions for the period 2006 to 2010 for each of the six plans. Because the HECO IRP-3 planning period begins in 2006, HECO does not have an emission estimate for 2005.

Projected SO_2 Emissions (Tons) for HECO IRP-3 Candidate Plans
Utility and Non-Utility Units Combined

		Plan 1	Plan 2	Plan 3	Plan 4	Plan 5	Plan 6
	IRP-2 Evaluation Report with Utility CHP	Least Cost Plan	Meets the State RPS Law -- Oahu Only	Maximize Renewable Energy Plan	Meets the State RPS Law	Maximize Fuel Diversity Plan	Combination Plan
2006	15,102	14,807	14,807	14,807	14,807	14,884	14,807
2007	15,485	15,088	15,088	15,088	15,088	15,221	15,088
2008	15,617	15,111	15,111	15,092	15,111	15,308	15,111
2009	16,100	15,461	15,461	15,149	15,461	15,448	15,187
2010	16,239	15,457	15,457	15,089	15,457	15,514	15,180

The projected SO_2 emissions include those from existing HECO generating units and those estimated by HECO from firm capacity Independent Power Producer units, including AES Hawaii, Kalaeloa and H-Power. HECO does not have actual SO_2 emission rates from these firm capacity Independent Power Producer units. For IRP purposes, HECO used estimates of emissions rates for these types of units (atmospheric fluidized bed combustion coal-fired unit, low sulfur fuel oil-fired combined cycle unit, and municipal solid waste generating unit) based on Unit Information Forms provided by a consultant for HECO's IRP-2 supply-side resource option evaluation.

The simple cycle combustion turbine to be installed in 2009 may range in size from 75 MW to 120 MW, depending on which turbine vendor is selected through a competitive bidding process to provide the turbine. For IRP purposes, it is assumed that a 76 MW calculations shown in the table above. The unit is needed sooner as HECO has an urgent need for capacity, but it cannot be installed sooner than 2009 due to the long lead times for permitting, equipment procurement and construction. The emission data in the table are based on the unit utilizing fuel with a sulfur content of 0.4% by weight. The type of fuel that will actually be used will be 0.35% sulfur diesel or 0.05% sulfur diesel or naphtha based on the air permit application for the unit. The 0.4% sulfur value was used for IRP purposes because it was the value available at the time the IRP database was being compiled. The actual amount of SO_2 emissions will be proportional to the amount of sulfur in the fuel and the actual amount of fuel used. HECO does not have candidate plans or emission data for the scenario where the unit is not installed in 2009.

e. HECO does not have a specific emissions target. Consideration is given to reducing PM10 emissions as well as to meeting many other IRP objectives.

CA-IR-295

a. Please describe HECO's plans relative to the recent legislation addressing a renewables portfolio standard for Hawaii.

b. Please indicate whether and how these plans affected decisions regarding the resources to be included for cost recovery in the instant rate case.

HECO Response:

a. See attached document (on pages 2 to 16 to this response) on current status of HECO Utilities to increase renewable energy. Conservation and energy efficiency are included as renewables in the current RPS legislation. A summary of HECO's plans for Demand-side Management programs are included in HECO T-11 and related exhibits.

b. The renewable energy activities related to the electronic shock absorber and Hawaii Biomass Programs are addressed in HECO T-6 testimony and related CA-IR-185 and 186. The RPS legislation did not affect plans for HECO's DSM programs.

Current Status of
HECO Utilities' Renewable Energy Efforts

What is HECO Utilities' strategy to increase renewable energy development in Hawaii?

HECO Utilities' strategy aims to:

(1) pursue commercially available renewable energy generation in the near term;
(2) pursue activities that can increase the number of intermittent renewable energy technologies (i.e., wind) on the electric grid), and in parallel,
(3) accelerate RD&D for emerging technologies and resources that are not currently commercially available or economically viable in the near term.

This strategy will ensure that the HECO utilities are not only taking action to use as much renewable energy as is commercially and economically viable today, but also are helping to develop future sources of renewable energy.

The HECO utilities' activities and initiatives are described in detail below:

(1) PURSUE COMMERCIAL RENEWABLE ENERGY PROJECTS

The HECO utilities are pursuing commercial renewable energy projects by (1) keeping *existing* commercial renewable energy projects operating and (2) pursuing *new* commercial renewable energy projects.

Keep Existing Commercial Renewable Energy Projects/Resources on the System

A key component of the HECO utilities' renewable portfolio strategy is to maintain the existing sources that are currently contributing renewable energy to the State's energy mix.

Puueo Hydro Rehabilitation

The existing 1.5 MW HELCO-owned run-of-river Puueo hydroelectric plant will be rehabilitated. The PUC approved HELCO's plans to rehabilitate the damaged generator by installing a modern, more efficient turbine generator with a capacity of roughly 2.28 to 2.4 MW.

Lalamilo Wind farm

The Lalamilo wind farm is an existing 2.28 MW HELCO-owned facility located in the Waimea area (Big Island). HELCO is presently considering options for increasing the output of this facility.

Puna Geothermal Ventures (PGV)

Due to well problems, the normal capacity of 30 MW at PGV had been reduced to an average of 5.6 MW from April to December 2002. PGV has drilled a new source well and converted KS-11 into a re-injection well, which has enabled PGV's output to slowly increase. PGV indicates that as of January 2004, it has been able to export roughly to 27 MW on a consistent basis.

Hawaiian Commercial and Sugar Company (HC&S)
MECO and Hawaiian Commercial and Sugar Company (HC&S) have agreed to have their power purchase agreement remain in effect at least through December 31, 2007, thus continuing the export of bagasse-generated and hydroelectric energy to the grid.

Continue existing DSM programs
Since its beginnings in 1996, our residential solar water heating program, the largest in the nation, has paid over $25 million in rebates to help 25,000 Hawaii households install solar. HECO has paid out nearly $21million in rebates for energy efficient technologies such as lighting, cooling, heating and motors in over 5,400 projects statewide.

In their second Integrated Resource Plan reports, HECO, HELCO and MECO all determined that their demand-side management (DSM) programs, including solar water heating and heat pumps, should continue to be included in future resource plans. Future rebates for solar water heating systems will provide an important incentive to encourage the adoption of solar water heating in the future. The HECO utilities continue to work towards obtaining PUC approval to continue, and expand, its DSM programs in the future.

In addition to utility planning efforts, the 2003 Legislature demonstrated vision and commitment to renewable energy by passing the Renewable Energy Tax Credit. This legislation in conjunction with the utility demand-side management programs provides a positive incentive for both solar water heating and other renewable technologies.

<u>Pursue and Facilitate New Commercial Renewable Energy Projects</u>
HECO utilities are also pursuing programs to facilitate the commercial development of wind and biomass resources, as well as a program to enhance the positive integration of renewable energy systems with the electric grid.

Stimulate renewable energy market
HECO formed a non-regulated subsidiary in December 2002 called Renewable Hawaii, Inc. to seek passive investment opportunities in cost-effective, commercial renewable energy projects in the State. With initial approval to invest up to $10 million, Renewable Hawaii's formation builds on HECO's ongoing commitment to increase Hawaii's use of renewable energy. The primary objectives of Renewable Hawaii are to stimulate the addition of cost-effective, commercial renewable energy in Hawaii, promote viable projects that will integrate positively with the utility grid, and encourage renewable energy generation activity where such is lacking in targeted categories. (Technologies requiring research and design, prototype development, or demonstration will not be considered.)

Renewable Hawaii is attempting to stimulate the renewable energy market by releasing a series of island-specific Renewable Energy Request for Project Proposals (RE RFPP). The following summarizes Renewable Hawaii's efforts thus far:

- <u>Island of Oahu</u>
  An RE RFPP for the island of Oahu was released on May 22, 2003 and closed on August 22, 2003. Eight proposals were received with three proposals passing the screening process. RHI is signing MOUs and project agreements for three renewable projects related to wind, solid waste and landfill gas.

- Maui County (islands of Maui, Molokai, and Lanai)
  An RE RFPP for the islands of Maui, Molokai, and Lanai was released on September 4, 2003 and closed on December 4, 2003. Five proposals were received; two proposals (wind) are currently undergoing detailed evaluation as the projects are developed.

- Big Island of Hawaii
  An RE RFPP for the Big Island of Hawaii was released on January 22, 2004 and closed on April 22, 2004. Four proposals were received, one proposal (solid waste) is undergoing detailed evaluation.

Another round of RE RFPP will be released in early 2005. In addition, Renewable Hawaii will be working with landowners and developers to develop other renewable energy projects in Hawaii.

Wind Program
Wind has a high potential for near-term commercial development because of the potential resource availability in Hawaii and the maturity of the technology. HECO has launched various wind initiatives:

- High Resolution Wind Resource Maps
  A new project funded by HECO, the Department of Business, Economic Development and Tourism (DBEDT), and the Department of Energy's National Renewable Energy Laboratory (NREL) has been initiated to update the State's wind resource maps. Preliminary high resolution wind resource maps, which graphically show wind power densities and wind speed, for the islands of Oahu, Big Island of Hawaii, Maui, Molokai, and Lanai have been developed to help identify new wind sites that could lead to commercial wind development.

- Commercial Wind Assessment
  As a result of the high resolution wind resource maps, HECO has begun a one-year study to verify the wind energy potential on the ridges above the company's Kahe Power Plant. In April 2004, HECO began monitoring wind speed, direction and turbulence to confirm the area's potential to generate electricity with wind. Other project feasibility issues, such as permitting and approvals, are being assessed. HECO and MECO are exploring wind resource monitoring at other locations.

- Offshore Wind Assessment
  In anticipation of the findings of the high-resolution wind resource maps, HECO hoped to conduct an assessment of potential offshore wind development on Oahu. However, the wind maps revealed that the offshore wind speeds were too low in areas having shallow depths (50 foot depths are necessary for offshore wind development using today's technology) and that the depths were too deep in areas having high wind speeds. Therefore, a study is not planned at this time.

- Hawaii Wind Working Group
  HECO and DBEDT co-chair the federal-sponsored Hawaii Wind Working Group (HWWG) as part of the Department of Energy's Wind Powering America

program. The functions of the HWWG are to provide a forum for information exchange on wind energy among member organizations, the public, and decision makers and to encourage the development of technically and economically feasible wind projects. Formed in 2002, the HWWG has held several meetings to exchange information.

Bioenergy Program

Biomass has a high potential for near-term commercial development because of the potential resource availability in Hawaii and the maturity of the technology. Initiatives to explore agricultural wastes and biofuels are underway.

- Hawaii Biomass Program
  HECO is working with HC&S and the University of Hawaii at Manoa to develop the Hawaii Biomass Program. This proposed multi-year program would take a collaborative approach in developing a policy and technology framework that would lead to commercialization of an economically viable way to make full use of the total sugarcane material (including the use of cane trash) as a biomass energy resource (i.e., implement a comprehensive dual-use crop strategy to economically produce both sugar and energy).

  Some Federal monies have been identified to conduct preliminary biomass resource assessment at the HC&S facility. Hawaii Natural Energy Institute researchers will lead this study.

- Biofuels Program
  The potential utilization of biofuels (e.g., biodiesel, ethanol, and biofuel blends) in existing and new power generation units is being explored under HECO's Biofuels Program. The use of biofuels in electric power generating units represents a potential near-term renewable energy option. Before biofuels can be used on a commercial basis, however, the technical feasibility of firing stationary power generating units will need to be evaluated and demonstrated. Program activities include the following:

  - HECO has funded a project to obtain information on biofuel properties, supply, availability, and pricing (Phase 1 of a planned multi-phase, multi-year biofuels assessment study). HECO is currently initiating Phase 2 of the program – obtaining performance and emissions data on a combustion turbine combustor on biofuels.

  - HECO is examining the feasibility of using boiler-grade fuel derived from used grease trap oil (such as the waste oil produced by restaurants) in its generating units.

  - MECO initiated the use of biodiesel during start-up operations in two of its generating units the Maalaea Generation Station.

  - After a one-year pilot program, HECO has converted its entire fleet of diesel-fueled trucks and associated refueling stations to use B20 fuel (20% biodiesel and 80% diesel).

Facilitate Non-Utility Projects
HECO, HELCO, and MECO receive and evaluate proposals from independent power producers seeking to sell power to the utilities. The following projects are either under review, in negotiations, or in the case of the Hawi project completed with negotiations.

- Union Mill Hydroelectric Project (HELCO)
  Power Tech Industries, Inc. is proposing an 800 kW hydroelectric facility (Union Mill) located at Hawi, Hawaii.

- Tradewinds (HELCO)
  Tradewinds, LLC has proposed to build and operate a wood processing plant to process eucalyptus trees into various wood products. The plant would include a cogeneration facility to generate electricity fueled by wood waste with excess electricity to be utilized on the HELCO grid. Tradewinds continues to pursue this project and HELCO has been in discussions with Tradewinds on the possible forms this project could take.

- Apollo Kamao'a Wind Farm (HELCO)
  Apollo Energy Corporation (Apollo) is proposing to repower its existing 7,000 kW wind farm (Kamao'a Wind Farm) located at South Point, Hawaii. Under the plans, the repowered wind farm would increase in size to 20,500 kW. On October 13, 2004, HELCO and Apollo signed a PPA for as-available energy from the repowered wind farm. HELCO submitted the PPA to the PUC for approval on November 26, 2004;

- Hawi Wind Farm (HELCO)
  Hawi Renewable Development LLC (HRD) and HELCO signed a power purchase agreement (PPA) on December 30, 2003 for as-available energy from a 10,560 kW wind farm at Hawi, Hawaii. The PPA was approved by the PUC on May 14, 2004. The PUC earlier (January 14, 2003) approved a signed PPA between HELCO and Hawi Renewable Development, Inc. (HRD Inc.) (executed January 8, 2001, as amended by Amendment No. 1 dated April 30, 2002) for as-available energy from a 5,280 kW wind farm at Hawi, Hawaii. Following execution of the PPA executed January 8, 2001, as amended on April 30, 2002, HRD decided to construct and operate a 10,560 kW wind farm, which would incorporate the original 5,280 kW wind farm at the same site. That necessitated further negotiations which resulted in the PPA signed on December 30, 2003. HRD has forwarded funds pursuant to the PPA to enable HELCO to proceed with construction of the necessary interconnection facilities.

- Kaheawa Wind Power Wind Farm (MECO)

Kaheawa Wind Power ("KWP") has proposed to develop a 30 MW wind farm on

The proposal received in late December 2003 proposes a July 2008 in-service date. If the project proves to be technically and economically feasible, the facility would be the first commercial OTEC facility in the world. HECO and SSPI are at the preliminary stages of discussions.

- H-Power Expansion (HECO)
  There have been informal, verbal comments by H-Power personnel that the City & County of Honolulu may want to expand the facility by adding a third boiler.

- Hawaii Energy Group Makila Hydro (MECO)
  Hawaii Energy Group, the consultant to the owner of Makila Hydro, is requesting an "as available" power purchase contract, for the proposed repowering of an existing 500 kW hydro generator located above Lahaina, (previously interconnected to Pioneer Mill). The parties have reached agreement on all key issues, and are now focused on completing the PPA

Assess Renewable Energy Technologies in IRP
HECO utilities conduct long-range planning to meet the energy needs of its customers. As part of their Integrated Resource Planning (IRP) process, HECO utilities evaluate both supply-side and demand-side resource options. Included in the IRP process is a comprehensive assessment of renewable energy resources and technologies that are feasible in the near-term

The Consumer Advocate submitted an interim report of the ad hoc advisory group to the Legislature in December 2003.

(2) PURSUE ACTIVITIES THAT CAN INCREASE INTERMITTENT RENEWABLE ENERGY

Renewable Energy Integration Program

The intermittent and variable nature of wind can put a major strain on the existing utility systems in terms of being able to control system frequency and power fluctuations, which can impact the reliability of power provided to customers. The smaller the electric grid system, the greater the impact these fluctuations may have on utility and consumer electrical equipment. HECO, HELCO, and MECO are conducting various projects to address this issue with the ultimate goal of allowing more wind on the utility systems.

- Electronic Shock Absorber
  To help stabilize operation of grid-connected wind turbines and minimize power fluctuations on an electric grid that is connected to a number of wind farms, HECO, HELCO, and MECO have teamed with a private company to conduct a study and confirm that a device can be developed from commercial products for installation between a wind farm and the utility grid. The purpose of the device, called the Electronic Shock Absorber (ESA), is to help the electric utility ride through short duration power fluctuations (frequency, voltage, etc.) from the wind farm caused by the variable nature of wind.

  A patent on the ESA device was filed by HECO and accepted in 2003. A demonstration ESA system is being built and is scheduled for testing in late 2005 at the HELCO Lalamilo wind farm site.

- Intermittent Generation Assessment Protocol (IGAP)
  To improve existing planning and evaluation tools, HECO is working with a consultant on the IGAP study to address the technical and cost impacts of relatively high levels of intermittent renewable energy generation on small, isolated electric utility systems.

  The study will develop improved modeling to quantify the impacts of high levels of intermittent generation, establish appropriate power quality standards, and identify specific measures that can be taken by intermittent generation operators and utility operators to mitigate power quality fluctuations.

- Grid Quality Assessment
  Through its membership with the Utility Wind Interest Group (UWIG), HECO plans to participate in a project to develop assessment tools related to grid quality. The purpose of this project is to determine and characterize the voltage fluctuations caused by wind farms on distribution feeder lines.

- In-line Hydro and Pumped Storage Hydro Assessment
  Under a partnership with HECO, HELCO, DBEDT, County of Hawaii, and the State Department of Agriculture, a study is being funded by DBEDT and HECO to identify the potential for in-line hydroelectric and pumped storage hydroelectric (i.e., PSH, use of wind during off-peak hours to pump water to a higher elevation and generating power through in-line hydro units during on-peak hours) in existing County, State,

and private water systems. Preliminary engineering on two sites have been conducted for possible PSH operations.

A similar study is being explored on the County of Maui water supply facilities. The Honolulu Board of Water Supply has stated that this PSH potential on existing infrastructure does not exist on their systems.

- Bulk Energy Storage to Relieve Transmission Congestion on the Big Island
  Under a partnership with HELCO, DBEDT, and Sentech, a study is being funded by the U.S. Department of Energy to investigate new forms of energy storage that could alleviate the issue of overloading transmission lines when transporting renewable electricity to end uses, fostering the increased use of distributed energy and renewable energy systems. Study has been completed and accepted by DBEDT in December 2004.

- Distributed Energy Resources Management as a Microgrid
  HECO and DBEDT have received funding under a U.S. Department of Energy competitive grant program to evaluate the combination of hybrid, controllable distributed energy resources (DER) systems that will encourage development of renewable and distributed resources. Study has been completed and accepted by DBEDT in December 2004.

(3) ACCELERATE THE DEVELOPMENT OF EMERGING RENEWABLE ENERGY TECHNOLOGIES

As part of the HECO utilities' strategy to increase the renewable portfolio in the long-term, the companies are pursuing a broad range of initiatives to facilitate and accelerate the development of emerging renewable energy technologies in Hawaii.

Investment Opportunities

HECO's parent company, Hawaiian Electric Industries (HEI), has provided venture capital funding to local companies engaged in emerging technology development to help accelerate technology deployment in Hawaii. HEI is involved with two companies developing renewable energy technology.

Hoku Scientific

In June 2002, HEI provided venture capital funding to Hoku Scientific, Inc., a Hawaii-based fuel cell R&D company that is developing proprietary fuel cell membrane technology. HEI's lead investment, which was part of a $1+ million first round of funding, was critical to the further development of Hoku Scientific and its technology.

Worldwide Energy Group

In December 2003, HEI provided venture capital funding to Worldwide Energy Group, Inc., a Hawaii-based company developing a technology that converts sugarcane bagasse or other biomass resources into ethanol. Ethanol is a potential alternative fuel produced from locally available renewable sources that can be used to generate electricity.

Research, development, and demonstration (RD&D)

RD&D projects and projects that enhance public education about renewable energy are also underway. HECO utilities' membership with the Electric Power Research Institute (EPRI), the research arm of the electric utility industry, keeps HECO utilities abreast of technology advances and is a core component of its RD&D thrust. In addition, HECO utilities will continue to seek partnerships with Federal, State, and County governments, the University of Hawaii, and other entities to increase its renewable energy portfolio.

RD&D projects, listed by technology, are described below.

Hydrogen and Fuel Cells

- <u>Hawaii Fuel Cell Test Facility</u>
  HECO has partnered with HNEI, U.S. Department of Defense (DOD), and UTC Fuel Cells to build and operate a hydrogen fuel cell test facility in Hawaii. The Hawaii Fuel Cell Test Facility, operational since April 2003, is housed in approximately 4,000 square feet of warehouse space at HECO's Ward Avenue facility and is used to evaluate the performance and reliability of production-sized, single-celled, fuel cell stack designs, materials, and fuels.

- <u>Hydrogen Power Park Study</u>
  HECO and HELCO are partnering with the DBEDT, HNEI, Sentech, Sunline, Stuart Energy, and UTC Fuel Cells in a project to introduce and demonstrate hydrogen-based infrastructure in Hawaii.

- <u>NELHA Gateway Energy Center Project</u>
  HELCO is partnering with the Natural Energy Laboratory of Hawaii Authority (NELHA), DBEDT, HNEI, and Sentech in a project to construct distributed energy systems at the Gateway Energy Center located at the entrance to NELHA's Hawaii Ocean Science and Technology (HOST) Park. This project aims to demonstrate renewable distributed energy resources and technology.

  In August 2004, HELCO installed two grid-connected 20 kW photovoltaic systems at the Gateway Energy Center. These systems utilize both multi-crystalline and amorphous silicon modules. Also, under a Million Solar Roofs U.S. Department of Energy Grant, HELCO has also partnered with NELHA and DBEDT to design and install an educational display at the Gateway Energy Center featuring solar technology.

  In addition, HECO and HELCO participated in the Electric Reliability Technical Roundtable meetings on the Big Island sponsored by the U.S Department of Energy. Federal monies have been identified for funding renewable energy development in Hawaii

Solar Energy

- <u>Photovoltaic Project at Ford Island</u>
  The Navy awarded a contract in late 2004 to install 200 kilowatts of photovoltaic equipment on the Navy's Hangar Building 54 rooftop at Ford Island. This contract represents several years of effort by Hawaii's Congressional delegation,

Navy Region Hawaii, the Hawaii Natural Energy Institute, and HECO to secure federal funding for a photovoltaic demonstration project on Oahu. PowerLight Corporation has been named as the prime contractor; the University of Hawaii's Hawaii Natural Energy Institute will be evaluating output data from the installation, and HECO will be assisting the Navy in technical matters related to installation and operation.

- Solar Roof Assessment Study
  HECO provided seed funds for a research effort by the University of Hawaii School of Architecture to develop a method for assessing the potential for solar power on roofs of existing buildings on the island of Oahu.

- Kona Base Yard Grid-Connect Photovoltaic System
  To demonstrate a net energy metered photovoltaic system that would be similar to what a small commercial or residential customer might consider, HELCO has installed a 5.4 kW photovoltaic system along with battery back up and an educational display at its Kona base yard.

- Solar Thermal/Cooling Pilot Project
  HELCO completed a pilot study in partnership with, Pacific Energy Services, Solel, and the Waikoloa Beach Marriott (An Outrigger Resort) to analyze whether a solar thermal panel could generate enough heat to drive an absorption chiller process and to use the data gathered to estimate the economics of a full scale solar cooling system. The pilot system, operational from April 2003 to May 2004, utilized one Solel SunPro, flat plate, solar panel in a closed loop system to heat a hot water/glycol solution to 180-250 °F. The Pacific Energy Services study estimated the payback at 6-7 years for a full scale system consisting of 190 (1m x 6m) solar thermal panels covering the entire rooftop of the Marriott, 100 ton absorption chiller, 210 ton cooling tower, new hot water heater, new pumps, and heat exchangers to provide chilled water, domestic hot water, and pool heating.

- Maui Building-Integrated Photovoltaics
  MECO provided a solar roof to the County of Maui's Lahaina Civic Center in November 2003. The roof serves the dual purpose of covering a walkway and providing the solar power for an electronic sign as well as parking lot lighting.

- U.S. Department of Defense Bus Stop Photovoltaic Lighting Demonstration
  To promote and demonstrate off-grid photovoltaic technology, HECO is working with the Army to install photovoltaic area lighting systems at existing bus stops and other facilities on military property (Schofield Barracks).

- HELCO Photovoltaic Area Lighting Projects
  To promote the use of off-grid photovoltaic applications, HELCO has partnered with various entities to install photovoltaic area lighting systems:

  - HELCO, the County of Hawaii, and the U.S. Department of Energy Million Solar Roofs (MSR) program teamed up to design and install a solar lighted educational kiosk and solar lighting for the Hilo bay front public restrooms.

- Two solar-powered lights provide dusk-to-dawn security and improve the safety of the parking lot at the Catholic Charities Community and Immigrant Services transitional shelter Ka Hale `O Kawaihae.

- A partnership between HELCO and the County of Hawaii was formed to provide improved lighting for two County parks located in Puna (Ahalanui Beach Park and Pohoiki Beach Park).

Hydroelectric Resources

- County of Hawaii In-line Hydroelectric Demonstration Project
  HELCO has committed funding to cost-share with the County of Hawaii Department of Water Supply for an in-line hydroelectric generator project.

- Lanai In-line Hydroelectric Study
  MECO, in conjunction with Castle & Cooke Resorts, initiated a feasibility study to examine whether an in-line hydroelectric system can be installed in the existing distribution water pipelines from central Lanai to its Manele Bay Resort.

Ocean Resources

- Navy Wave Energy Demonstration
  Under a DOD Small Business Innovation Research (SBIR) grant, the Navy is partnering with Ocean Power Technologies (OPT) to assess the technical and economic feasibility of ocean wave energy. An at-sea demonstration of a 20-kW buoy wave energy system will be conducted at Kaneohe Marine Base. HECO provided engineering support regarding interconnecting to the electric grid and also serves as a Navy technical advisor.

  The OPT unit has operated for several months at sea providing mechanical energy. Several components of the unit are being upgraded before redeployment in 2005. New design features will be employed as a result of these tests.

- EPRI Offshore Wave Energy Project
  HECO is participating in a project headed by EPRI to demonstrate the feasibility of wave power. The project examined design issues, performance, and costs of Ocean Power Delivery's Pelamis (sea snake) technology operated offshore of Makapuu. The technology still has technology challenges to overcome before reaching a commercial state.

  The role of the U. S. Department of Energy in ocean energy development is non-existent. The federal government has to recognize the potential of ocean energy for the nation and include ocean energy in its program and budget if ocean energy is to develop and mature along a similar path as wind energy (developed in the early 1970s and 1980s and maturing in the 1990s and 2000s).

- Honolulu Board of Water Supply (BWS) Deep Ocean Water Application Facility Study
  The BWS is evaluating the feasibility of developing a deep ocean water facility to produce potable water, generate power via OTEC, and provide chilled water (seawater) for air conditioning and other applications. HECO is serving on the study's advisory group.

Public Education

- Sun Power for Schools Program
  HECO, HELCO, and MECO are entering the 9th year of their Sun Power for Schools program with the State of Hawaii Department of Education. Through the Sun Power for Schools program, HECO utilities will continue to install photovoltaic systems at Hawaii public schools using voluntary customer contributions and by providing in-kind utility contributions, including engineering, project management, administration, advertising, and marketing. To date, twenty (20) public schools have received photovoltaic systems totaling over 23,000 watts (ten on Oahu, four on the Big Island, and six in Maui County). HECO has extended the program for another two years (2005-2006).

  HECO has plans to install four photovoltaic systems – one each at Jarrett Intermediate, Waianae Intermediate, Nanakuli High/Intermediate and Highlands Intermediate schools in 2005. MECO is currently working to install two 1.25 kW PV systems (using "triple-junction" amorphous modules and single crystal modules for side-by-side comparison of the performance) and a shade structure at Lanai High School. HELCO is currently working to install one 1 kW PV system at Konawaena Middle School.

  HECO and the State of Hawaii Department of Education developed educational materials through a grant from the U.S Department of Energy's Million Solar Roofs program. The material was provided to public high school teachers. HECO, HELCO and MECO also conducted workshops for public high school and middle school teachers and participated in their Solar Sprint program where students evaluate their solar cars in field tests.

- Bishop Museum Energy Pavilion
  Increasing public education and awareness of renewable energy technology is an important step towards establishing a sustainable market for renewable energy. HECO provided funding for a 1.5 kW grid-connected photovoltaic system and renewable energy exhibit located at Bishop Museum. The photovoltaic energy system and exhibit, called *Hale Ikehu*, is operational and open to the public. Visitors are able to observe a working photovoltaic system and learn about solar energy and other renewable energy technologies. During the first seven months, over 600 individuals directly participated in the Hale Ikehu educational programs and over 110,000 visitors to Bishop Museum had the opportunity to view the renewable energy displays and educational materials.

- West Oahu Wind Education Efforts

In response to requests from community leaders and Hawaiian cultural representatives in the Leeward area, HECO is undertaking several wind education efforts targeted at the area around the Kahe power plant, where wind monitoring is underway. These on-going efforts include a series of information ads in two community publications, educational displays and games at community events and support for a video about wind energy being created by video students at Nanakuli High School for presentation in the community and on 'Olelo public access cable television.

- <u>HECO Renewable Energy Website</u>
  More information about the HECO Utilities' renewable energy programs and initiatives can be found on HECO's website at <u>www.heco.com</u> under 'Renewable Energy'.

HECO Utilities are also involved in other activities that encourage the use of renewable energy in Hawaii.

<u>Expand solar water heating and heat pump DSM programs</u>

City and County of Honolulu Solar Roofs, Low-Income Solar Loan Program

To increase participation in HECO's Residential Efficient Water Heating Program ("REWH"), HECO entered into a partnership with the City and County of Honolulu to offer loans for the installation of solar water heating systems to low to moderate-income customers. Working with the Rehabilitation Loan Branch of the Department of Community Services has enabled HECO to offer these low-interest loans with a minimal amount of additional cost to the program.

The interest rate from the loan repayment is either 0% or 2% based on the applicant's income. The term of the loan is 7 years and generally gives customers monthly payments equal to or only slightly greater than the energy savings on their electric bill resulting from the installation of the solar system.

The loan program was introduced in April 2003 and as of November 2004 resulted in 55 approved loans.

Maui Solar Roofs Initiative

In September 2002, MECO formed a partnership with the County of Maui to increase the use of renewable energy in Maui County by increasing the number of solar water heating systems installed in residences. The County provided a grant in the amount of $250,000 to MECO to establish a revolving fund, administered by MECO, offering zero-interest loans to qualified homeowners. The loan would help finance the up front costs of installing a solar water heater on their home.

The fund is rebuilt as the approved applicants repay their loans. During the first year, 116 applications were approved of which 40% of the applicants were below the median income. Based on the program's success after its first year, MECO received two additional $100,000 grants from the County's Office of Economic Development (for use in fiscal year 2004 and 2005). The program was modified to reserve at least 50% of the funds for applicants with household income below the median with priority going to low-income applicants. To date, 267 applications have been received of which 184 were approved.

MECO received a grant of $50,000 from the Department of Energy's Million Solar Roofs Initiative. The funds will be used for public education on the benefits of solar energy, including an upgrade to MECO's website for greater access for our tri-island customers and the construction of a portable table top sized model home demonstrating energy efficient technologies, materials and components at public events. The grant will also support the development of financing strategies for solar installations on non-profit facilities, such as the Westside Resource Center in Lahaina.

USDA Rural Utilities Service's Grant to Fund MECO's Solar for Molokai Project

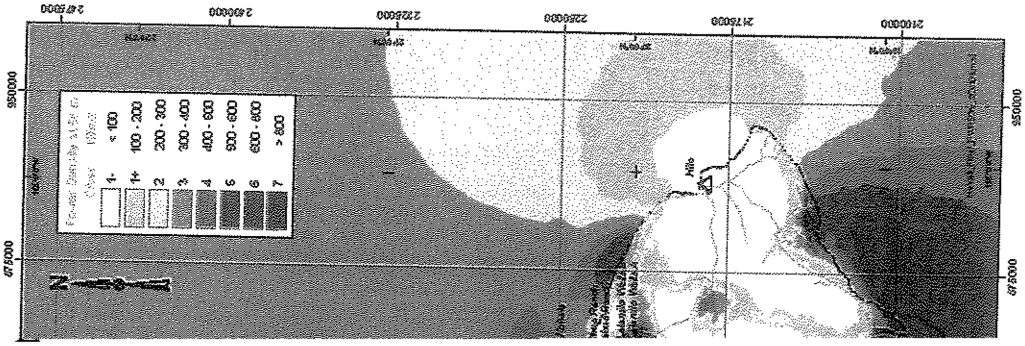
To further help make solar water heating more affordable for those who might not otherwise be able to invest in it, MECO received in May 2004 over $1.1 million in USDA funds for the installation of renewable energy solar water heating systems on the island of Molokai. MECO will provide about $400,000 in rebates, as well as project administration and outreach. Approved applicants will be required to attend classes to learn about basic solar system maintenance to ensure maximum performance over the life of the system and other energy saving techniques.

Community partners include the Department of Hawaiian Home Lands, Maui Economic Opportunity, Department of Housing and Human Concerns, Molokai Community Services Council, Office of Hawaiian Affairs, and Ke Aupuni Lokahi, which oversees the island's Enterprise Community efforts. The Energy, Resources and Technology Division of DBEDT will assist in conducting the educational classes. To date, 22 solar water heater systems have been installed with another 35 approved applicants.

Big Island Solar Roofs Program

To increase participation in HELCO's Residential Efficient Water Heating Program, HELCO has entered into a partnership with CU Hawaii Federal Credit Union that features two low interest solar loan programs. The first program offers 0% loans with a five year term to qualifying low income households. The annual fund will provide for approximately 28 residential solar water heating loans. To provide a loan rate of 0% for this program, HELCO will pay the interest portion of the loans. The loan fund for this program is limited to $100,000 per year.

The second loan program provides loans at a nominal rate of 3% with a five year term. Funds for loans under this program are unlimited. The objective of this loan program is to service those customers who do not qualify as low-income but who satisfy CU Hawaii Federal Credit Union lending criteria.



CA-IR-296

Ref: HECO Response to CA-IR-16; Production Department Outside Services-General, EE=501 Projected Test Year Expenses.

For each of the following Honolulu Power Plant Maintenance RA=PIN Activities, test year projected Outside Services costs appear to be excessive relative to historical actual expenditure levels in the years 1999 through 2004. Please explain why the Company's projections should be viewed as reasonable under these circumstances and state specifically

[redacted]

work to be done has increased. Basing future rates on the average historical level of expenditures (or based on "trends" at the power plant activity level) would adversely impact generation availability, efficiency or safety because it will not provide sufficient resources to keep up with growing maintenance (generating unit and infrastructure) needs. To illustrate the need for HECO's proposed 2005 TY budget, four summarized trends are provided on page 5 that compares 1999 – 2004 Actual expenditure levels with the 2005 TY Budget. The trends are

Hawaiian Electric Company, Inc.
Select ABM Activities by Plant Site
1999-2004 Actual and 2005 Budget

Act	Act Description	1999	2000	2001	2002	2003	2004	Budget 2005
a)								
	(ALL COST CATEGORIES)							
265	Maint Common Struct - Corrective							
	Honolulu	313,334	432,309	241,501	220,017	255,669	309,554	444,868
	Waiau	523,258	1,878,325	914,446	1,153,270	571,855	1,579,727	1,689,770
	Kahe	547,404	1,565,255	1,012,394	699,337	555,373	937,702	921,957
	Oth-Not Assigned	8,653	15,460	3,801	0	1,920	4,889	0
		1,392,649	3,891,349	2,172,142	2,072,624	1,384,817	2,831,872	3,056,595
	(ONLY OUTSIDE SERVICE)							
265	Maint Common Struct - Corrective							
	Honolulu	135,465	264,919	115,489	91,395	77,077	124,849	226,800
	Waiau	155,532	1,478,597	533,357	614,777	264,360	1,233,078	1,009,004
	Kahe	279,858	1,179,692	626,884	312,446	126,937	519,470	541,400
	Oth-Not Assigned	2,910	13,500	3,717	0	891	1,403	0
		573,765	2,936,708	1,279,447	1,018,618	469,265	1,878,800	1,777,204
b)								
	(ALL COST CATEGORIES)							
270	Maint Fuel Feed Sys-Pred							
	Honolulu	91,154	273,375	0	111,856	205,523	73,125	285,000
	Waiau	0	0	0	0	0	0	20,149
	Kahe	0	0	0	0	0	0	0
		91,154	273,375	0	111,856	205,523	73,125	305,149
	(ONLY OUTSIDE SERVICE)							
270	Maint Fuel Feed Sys-Pred							
	Honolulu	84,923	262,147	0	103,794	133,446	73,125	285,000
	Waiau	0	0	0	0	0	0	0
	Kahe	0	0	0	0	0	0	0
		84,923	262,147	0	103,794	133,446	73,125	285,000
c)								
	(ALL COST CATEGORIES)							
260	Maint Steam Turbo Eq-Prev							
	Honolulu	56,440	169,648	69,364	260,783	2,267,349	34,152	291,204
	Waiau	280,529	2,437,327	1,029,024	891,937	874,549	1,340,570	2,224,738
	Kahe	1,971,211	788,343	1,494,111	1,258,286	294,342	1,299,902	2,385,896
		2,308,180	3,395,318	2,592,499	2,411,006	3,436,240	2,674,624	4,901,838
	(ONLY OUTSIDE SERVICE)							
260	Maint Steam Turbo Eq-Prev							
	Honolulu	0	45,968	24,736	18,121	491,087	234	80,000
	Waiau	19,085	970,069	418,754	389,186	260,870	516,865	557,000
	Kahe	196,134	60,070	286,655	407,464	4,484	265,088	242,250
		215,219	1,076,107	730,145	814,771	756,441	782,187	879,250

Hawaiian Electric Company, Inc.
Select ABM Activities by Plant Site
1999-2004 Actual and 2005 Budget

Act	Act Description	1999	2000	2001	2002	2003	2004	Budget 2005
d)								
	(ALL COST CATEGORIES)							
262	Maint Steam Turbo Eq-Corr							
	Honolulu	216,625	240,390	239,139	208,303	1,682,003	320,305	368,231
	Waiau	1,015,756	1,650,735	1,271,386	1,683,771	1,178,723	1,404,781	1,177,962
	Kahe	1,749,729	1,703,475	1,873,521	1,958,524	1,695,287	2,336,320	1,679,944
		2,982,110	3,594,600	3,384,046	3,850,598	4,556,013	4,061,406	3,226,137
	(ONLY OUTSIDE SERVICE)							
262	Maint Steam Turbo Eq-Corr							
	Honolulu	32,882	100,352	83,203	65,757	820,960	147,500	256,000
	Waiau	240,665	583,430	345,806	612,573	395,432	220,408	315,000
	Kahe	605,845	704,935	686,234	585,858	211,834	1,088,602	472,500
		879,392	1,388,717	1,115,243	1,264,188	1,428,226	1,456,510	1,043,500
e)								
	(ALL COST CATEGORIES)							
259	Maint Boiler Plt Eq-Corrective							
	Honolulu	278,400	474,369	479,931	538,795	1,615,880	501,702	590,295
	Waiau	2,680,480	2,646,297	2,035,968	1,918,081	1,604,981	2,724,241	3,529,520
	Kahe	2,737,417	2,873,070	2,998,884	3,238,759	3,272,694	3,877,700	3,720,045
		5,696,297	5,993,736	5,514,783	5,695,635	6,493,555	7,103,643	7,839,860
	(ONLY MATERIALS)							
259	Maint Boiler Plt Eq-Corrective							
	Honolulu	49,320	126,202	154,415	161,446	545,136	86,427	195,790
	Waiau	737,593	884,814	749,233	591,431	322,922	926,654	498,991
	Kahe	753,412	748,971	878,356	1,602,117	1,593,307	1,118,844	1,238,181
		1,540,325	1,759,987	1,782,004	2,354,994	2,461,365	2,131,925	1,932,962
f)								
	(ALL COST CATEGORIES)							
258	Maint Boiler Plt Eq-Predictive							
	Honolulu	35,091	131,823	49,583	174,395	441,224	194,418	523,824
	Waiau	358,531	523,307	602,707	481,843	423,080	2,552,365	608,335
	Kahe	441,426	492,305	1,152,316	1,001,186	1,458,493	1,296,022	1,611,717
		835,048	1,147,435	1,804,606	1,657,424	2,322,797	4,042,805	2,743,876
	(ONLY MATERIALS)							
258	Maint Boiler Plt Eq-Predictive							
	Honolulu	2,502	10,740	2,821	99,613	46,880	160,194	437,520
	Waiau	87,017	121,886	54,305	250,394	(49,806)	819,653	245,668
	Kahe	50,787	74,184	460,139	342,606	518,649	284,405	1,025,437
		140,306	206,810	517,265	692,613	515,723	1,264,252	1,708,625

Hawaiian Electric Company, Inc.
Select ABM Activities by Plant Site
1999-2004 Actual and 2005 Budget

Act	Act Description	1999	2000	2001	2002	2003	2004	Budget 2005
g)								
	(ALL COST CATEGORIES)							
878	Comply Solid & Hazard Waste Non-Oil							
	Honolulu	64,857	710,627	251,356	75,316	86,554	142,597	118,909
	Waiau	229,672	324,581	230,274	223,528	171,601	294,095	186,146
	Kahe	141,958	185,339	83,934	65,092	74,282	57,874	118,829
		436,487	1,220,547	565,564	363,936	332,437	494,566	423,884
	(ONLY OUTSIDE SERVICES)							
878	Comply Solid & Hazard Waste Non-Oil							
	Honolulu	37,551	696,120	241,371	64,984	70,389	112,614	102,004
	Waiau	146,018	234,963	194,055	174,280	81,824	174,351	164,000
	Kahe	93,930	156,870	54,641	34,971	47,728	17,741	69,000
		277,499	1,087,953	490,067	274,235	199,941	304,706	335,004

	1999	2000	2001	2002	2003	2004	Budget 2005
Select Activities - Total	13,741,925	19,516,360	16,033,640	16,163,079	18,731,382	21,282,041	22,497,339
Select Activities - O/S	2,030,798	6,751,632	3,614,902	3,475,606	2,987,319	4,495,328	4,319,958
Select Activities - Material	1,680,631	1,966,797	2,299,269	3,047,607	2,977,088	3,396,177	3,641,587
Prod Maint - Total	17,797,879	24,377,251	22,521,089	24,880,145	24,879,004	30,170,449	31,003,585
Prod Maint - O/S	1,753,299	5,663,679	3,124,835	3,201,371	2,787,378	4,190,622	3,984,954
Prod Maint - Material	1,680,631	1,966,797	2,299,269	3,047,607	2,977,088	3,396,177	3,641,587
Prod Operation - Total	16,672,776	21,189,666	20,150,357	19,414,340	20,173,225	20,286,317	24,281,898
Prod Operation - O/S	277,499	1,087,953	490,067	274,235	199,941	304,706	335,004
Prod Operation - Material	0	0	0	0	0	0	0
Prod Oper & Maint - Total	34,470,655	45,566,917	42,671,447	44,294,486	45,052,229	50,456,766	55,285,483
Prod Oper & Maint - O/S	6,570,144	14,098,695	12,059,160	10,481,314	10,949,289	14,629,722	14,441,758
Prod Oper & Maint - Material	5,251,503	6,742,685	7,070,443	8,923,138	8,605,786	10,492,575	8,162,831

CA-IR-297

<u>Ref: HECO Response to CA-IR-2, HECO T-6, Pages 17-21, Production Department Outside Services.</u>

For the Honolulu Power Plant, please provide a history of the Company's performance of the following activities (that are included in the test year expense forecast) for <u>each</u> year from 1999 through 2004, explaining why the projected activities and costs are reasonable in light of historical work requirements and the expected frequency of future performance of such work after 2005:

a.	Iwilei HPP FO Pipeline Pigging	$160,000;
b.	Budget Recycle	$ 80,000;
c.	Can't Locate Support	$ 45,000;
d.	Building Repairs	$ 60,000;
e.	Deck Plating Repairs	$ 50,000;
f.	Circ Water Pump Rpr	$ 80,000;
g.	Burner Tip Replacement	$150,000;
h.	H09 Boiler Chem Cln add	$400,000; and
i.	Asbestos Removal	$ 50,000.

<u>HECO Response:</u>

Please refer to HECO's response to CA-IR-296. The activities are provided for each item

g. Activity 259 – Maint Boiler Plt and Rel Eq-Corr

h. Activity 258 – Maint Boiler Plt and Rel Eq-Pred

i. Activity 878 – Comply w/ Ongoing Permit Req Req-Non-Oil Rel

CA-IR-298

Ref: HECO Response to CA-IR-16, Production Department Projected Labor Hours.

Each of the Production Department RA's spreadsheet file "Copy of Hours Extract.xls" when sorted and sub-totaled by RA, indicates that the projected Test Year 2005 labor hours significantly exceed historical actual labor hours incurred in the years 1999 through 2004. [redacted]

maintenance has not been done in the past, but will be commenced in 2005 within each RA to require the projected increase in total labor hours:

Test Year 2005 labor hours estimates. The impact of unpaid merit overtime hours is reflected for RA's that are staffed primarily by merit employees.

a. PIB (Admin-Power Supply O&M) Test Year labor hours are higher than past years due to:

- O&M Department Secretary retired in October 2003 and was replaced in April 2004. Actual hours in the years 2003 and 2004 for PIB were reduced by this vacancy. The Test Year 2005 labor hours were increased to reflect this position being filled for the entire year. The Department Secretary performs administrative and secretarial duties associated with Department activities.
- One Trainer has been added to PIB in the 2005 Test Year forecast. As explained in CA-IR-48, page 16, Note (1), an additional full time trainer is required to support compliance and competency training requirements for the combination of Operator and Shift Supervisor staffing changes, increased regulations, and application of new technologies. This Trainer position was filled on April 18, 2005.
- One IT Specialist has been added to PIB in the 2005 Test Year forecast. As explained in CA-IR-48, page 16, Note (2), the Power Supply Process Area depends heavily on technology to ensure compliant, safe, reliable, and efficient operations. The IT Specialist will provide user support, security administration, troubleshooting support, training, and document management support for all of the various business software applications.
- As reflected in CA-IR-172, PIB Test Year 2005 forecast includes 1177 overtime labor hours. As the PIB work group consists primarily of merit exempt employees, these "overtime" hours reflect distributed unpaid labor hours. As shown in CA-IR-172, paid overtime hours in PIB for 2002, 2003, and 2004 are 0, 15, and 5, respectively. It is not possible to determine the split of the 1177 overtime hours into direct labor and indirect

labor accounts. A comparison of past year recorded paid labor hours with Test Year 2005 distributed labor hours will lead to inaccurate conclusions. The Standard Labor Rates are used to calculate the total labor cost for the group, adjusting for the 1177 labor overtime hours.

b. As stated in HECO T-6, page 23, beginning at line 10, staffing level for PIH (Honolulu Station Operations) has been increased in 2005 Test Year forecast to increase Honolulu 8 and 9 unit availability from two 8-hour shifts per day and 5 days a week (10 separate work shifts per week) to three 8-hour shifts per day and 7 days a week (21 separate work shifts per week). To provide the necessary coverage for the additional 11 work shifts, PIH staffing was increased by 7 Operators and 1 Shift Supervisor over the April 30, 2004 staffing level as reflected in CA-IR-48, page 11 (19 Operators vs. 12, and 5 Shift Supervisors vs. 4). The increased headcount for the Operators was achieved on March 3, 2005 and training was started. Once the training is complete, the 24X7 scheduling can be initiated. The Shift Supervisor vacancy has been accepted by a PIH Operator. Transfer of the Operator to the Shift Supervisor position will occur once the newly hired Operators have completed their training and take over their staffing position. The transition to 24x7 for the Honolulu Power Plant will be completed on June 27, 2005, and will be maintained into the foreseeable future.

c. As stated in HECO T-6, page 28, beginning at line 22, Maintenance Division staffing level is being increased by a total of 20 to allow for the formation of night maintenance crews. 10 personnel of the 20 total are in PIL. This increase for PIL staffing level from 2004 to 2005 separation, promotion, or transfer. This is reflected in CA-IR-48, page 12. Effective April 4, 2005, the last vacancy was filled and PIN is fully staffed at its normal staffing level. Because of the small size of the work group, small changes in available personnel can have a great impact on available resources. As examples,

- The personnel in PIN are seasoned employees with many weeks of available vacation. As a group, PIP employees take approximately 1600 hours of vacation a year. This is equivalent to the loss of 1 productive employee. By increasing the staffing in PIP by 1 employee, this lost productive time can be offset.
- With the anticipated increase in running hours of H8 and H9, we also anticipate an increase in maintenance requirements.

e. PIP (Planning Division) is responsible for planning and scheduling all maintenance activities including Planned Outages, Maintenance Outages, operational maintenance, and occasional Forced Outage requirements.

The staffing additions to PIP in TY2005 over the actual staffing level as of 12/31/04 are described in CA-IR-48, page 13. These additions include replacements for (2) Resource Planners due to transfers, (1) Planning/Project Coordinator due to resignation, and (2) O&M Engineers due to retirement and transfer. New additions to PIP include (2) Resource Planners and (1) Planning/Project Coordinator to provide the ability to plan maintenance activities with back-to-back unit outages and concurrent operational maintenance activities caused by lower reserve margins and operating aging units harder. The Planned vs Actual maintenance outage schedules shown in CA-IR-41, Attachment 1, and CA-IR-42, Attachment 1, for 2003 and 2004 respectively illustrate the planning and scheduling challenges.

f. Labor hours in PIT (Traveling Maintenance) increase in 2005 Test Year with the addition of personnel to fill vacancies due to retirement, involuntary separation, promotion, and also to support higher workload. These additions are described in CA-IR-48, page 13 to 14, and will provide additional capability to support multiple and concurrent Planned Outages, Maintenance Outages and occasional Forced Outage support.

g. As stated in HECO T-6, page 23, beginning at line 10, staffing level for PIW (Waiau Station Operations) has been increased in 2005 Test Year forecast to increase Waiau 3 and 4 unit availability from two 8-hour shifts per day and 5 days a week (10 separate work shifts per week) to three 8-hour shifts per day and 7 days a week (21 separate work shifts per week). To provide the necessary coverage for the additional 11 work shifts, PIW staffing increased by 4 Operators as reflected in CA-IR-48, page 14. The transition to 24x7 for W3&4 was completed on March 21, 2005.

h. As stated in HECO T-6, page 28, beginning at line 22, Maintenance Division staffing level is being increased by a total of 20 to allow for the formation of night maintenance crews. 10 personnel of the 20 total are in PIX. This increase for PIX staffing level from 2004 to 2005 Test Year is reflected in CA-IR-48, page 14-16. The need for the night maintenance crew is discussed in HECO T-6, page 29, beginning at line 20.

CA-IR-299

Ref: HECO Response to CA-IR-100.

With regard to the 48% customer classification of distribution poles in the cost of service study, please respond to the following:

a. Confirm that HECO's minimum installed size pole is 30 feet.

b. Explain how the zero intercept study results on page 2 of the response to CA-IR-100 (negative $318) were interpreted for use in the cost of service study.

c. Describe how many customers per pole, or poles per customer, are required to establish service, relative to expanding the system to serve residential customers.

[redacted]

number of poles will be required to serve a single customer.

d. As indicated in HECO's response to subpart c. above, the number of poles required to provide service is dependent on the existing electrical infrastructure in the area, the [redacted]

proximity of the infrastructure to the customer's service site, and the estimated kW load of the customers to be served. For single family home developments (subdivisions) where the residential customer density is relatively lower, HECO's distribution system required to serve this subdivision will likely consist of several poles spread throughout the subdivision. In the case of a multi-family high rise building where the residential customer density (and corresponding estimated electrical demand) is considerably higher, depending on the proximity of the building to the existing infrastructure, HECO's distribution system required to serve this high rise building may consist of a fewer number of poles. In many cases only a single pole may be necessary, and HECO will typically provide either a set of double primary risers up a single pole in order to connect primary conductors to a pad-mounted transformer located on the [redacted]

CA-IR-300

<u>Ref: HECO Response to CA-IR-100.</u>

With regard to the 60% customer classification of distribution transformers in the cost of service study, please respond to the following:

a. Confirm that HECO's minimum installed distribution transformer is 25 kVa.

b. Explain how the zero intercept study results on pages 14, 22 and 38 of the response to CA-IR-100 were interpreted for use in the cost of service study.

c. Describe how many customers are typically served per transformer, relative to the expansion of the distribution system to serve residential customers.

d. Explain how residential customer density affects the number and types of transformers required to provide service, with reference to multi-family high rise buildings versus single family homes.

e. What is the demand serving capacity of a single 25 kVa transformer and how has any demand serving "credit" been provided to the residential class (in the demand allocation factor determination) after having customers pay for such transformers on a "customer" basis of allocation?

<u>HECO Response:</u>

a. While HECO may still have a few existing 10 kVA transformers on its distribution system, 25 kVA is the minimum size transformer that is currently stocked and installed. In other words, any new or replacement distribution transformer will be sized a minimum of 25 kVA.

b. [illegible]

customer from the transformer.

d. The size and total number of transformers required to feed a particular subdivision depends on the estimated demand for each customer, as well as the distance between each customer's service point. For single family home developments (subdivisions), where the residential [redacted]

lower- sized, single-phase, transformers (either pole or pad mounted) spread throughout the subdivision. In the case of multi-family high rise buildings, where the residential customer density (and corresponding estimated electrical demand) is considerably higher, HECO's

HECO-2201.

CA-IR-301

Ref: HECO Response to CA-IR-100.

With regard to the 42% customer classification of distribution conductors in its cost of service study, please respond to the following:

a. Confirm that HECO's minimum installed conductor is sized to serve 106 amps.

b. Explain how the zero intercept study results on pages 3 and 4 of the response to CA-IR-100 were interpreted for use in the cost of service study.

c. Describe how the minimum system conductor study results are translated into the values set forth in WP-2202 at page 147.

d. Explain how residential customer density affects the amount of conductor required to provide service to each customer, with reference to multi-family high rise buildings versus single family homes.

HECO Response:

a. HECO's minimum installed distribution conductor is sized to serve 106 amps.

b. The minimum intercept method seeks to identify the portion of the plant related to a hypothetical "no load" situation. The intercept value of the regression analysis is interpreted as the customer-related component of the plant cost. The negative intercept value is interpreted as not reasonable as it implies a negative customer-related cost for a hypothetical "no load" situation.

c. The customer-related component for conductors is based on the results of the minimum system method for primary conductors and secondary conductors (Account 367) weighted by the quantity of installed conductors for 1992-1998. See HECO-WP-2202, pages 160-172. The demand-related component for conductors is derived as 1 minus the customer-related component.

d. For newer single family home developments (subdivisions), where the residential customer density is relatively low, HECO's distribution system will likely consist of several pad-mounted transformers and an extensive network of both primary and secondary conductors which will be used to provide secondary service to each customer. On the primary side, typically these pad-mounted transformers will be connected via a single-phase loop, whereby the underground conductors will basically daisy-chain from one transformer to the next. On the secondary side, each individual customer will either connect directly back to the transformer with secondary conductors, or tap off of a main secondary feeder which is directly connected to the transformer, and is used to feed multiple customers.

In the case of multi-family high rise buildings, where the residential customer density (and corresponding estimated electrical demand) is considerably higher, HECO's distribution system will likely consist of a single, larger-sized, three-phase, pad-mounted transformer and a considerably lower amount of both primary and secondary conductors which will be used to provide secondary service to each customer. In this case, on the primary side, typically two sets of three phase underground conductors will run from a

CA-IR-302

Ref: Residential Use Model, Appendix H, Page 17 of the February 2004 voluminous workpapers.

The Consumer Advocate notes that the regression statistics indicate only two iterations to derive the regression results.

a. Please provide the estimation options used by the software package (MetrixND) to determine HECO AR residential model such as the maximum number of iterations and the convergence criterion.

b. Please provide a copy of the results of the residential use model with greater precision (i.e., that may produce more iterations to derive the regression equation).

HECO Response:

a. MetrixND has a maximum of 100 iterations and does not allow user input into the specification of the number of iterations run. Convergence is governed by the capabilities of the computers used to run MetrixND and is also not subject to input by the user.

b. See response to part a. above. HECO is unable to specify that MetrixND run more iterations to derive the regression equation.

CA-IR-303

<u>Ref: Weather normalization, February 2004 voluminous forecast, Appendix P, page 41 to 47.</u>

a. In Appendix P, page 43, the cooling degree day (CDD) impact factor appears to be steadily increasing until 1998 after which the factor appears to level off or stabilize.

   1. Please discuss the possible reasons for the slowdown in growth of the CDD impact factors in recent years.

   2. Please provide the data used for the weather normalization calculations on diskette.

b. In determining its weather normalization methodology, did HECO rely on methods used by other studies? If so, please provide copies of the studies.

<u>HECO Response:</u>

a. HECO updated its weather study in February 2004. The CDD impact factor through 2004 was provided electronically in response to CA-IR-162 as *CA-IR-162 PCMLWX 04.XLS*. An error was found in the 1981 customer data used to derive the factors in *CA-IR-162 PCMLWX 04.XLS*, and the corrected file is being provided electronically as *CA-IR-303 PCMLWX 04.XLS* on a CD in a folder labeled CA-IR-303 filed under separate transmittal.

   1. It is difficult to determine the reasons for the slowdown in growth of the CDD impact after 1998, however, it is possible that the slowdown may be due to changes in customer behavior, improved energy efficiency of various appliances including water heaters and air conditioning, adoption of new technologies such as solar water heating or zone air conditioning, or replacement of older chillers and air conditioning in commercial buildings with energy efficient equipment.

   2. The data is provided electronically in the file *CA-IR-303 04 WX DATA.XLS* on a CD in a folder labeled CA-IR-303 filed under separate transmittal.

b. HECO has evaluated its weather normalization methodology for electricity sales in studies conducted in 1986, 1987, 1996 and 1997. The 1987 evaluation was performed by HECO's consultant, Stone & Webster. The three studies in 1986, 1996, and 1997 were conducted by HECO. HECO has not relied on methods used by studies conducted by/for outside parties.

The studies are voluminous but can be made available for review at HECO. Please contact Irene Sekiya at 543-4778 to arrange for review.

CA-IR-304

a. Please provide specific reference to all testimony and briefs relating to the issues of lost revenues and utility incentives prepared by or for HECO within the last five years.

b. Please provide copies of any public statements relating to the issues of lost revenues and utility incentives prepared by or for HECO within the last five years.

HECO Response:

a. Two dockets specifically cover the issue of lost revenues and utility incentives within the last five years, Docket No. 00-0169 (For Approval of the Commercial and Industrial Demand-Side Management Program, Recovery of Program Costs and Lost Margins, and Consideration for Shareholder Incentives) and Docket No. 00-0209 (For Approval of a Residential Demand-Side Management Program, Recovery of Program Costs and Lost Margins, and Consideration for Shareholder Incentives). Please see page 2 of this response for the references to testimony and briefs for these two dockets.

b. Copies of HECO public statements relating to lost revenues and utility incentives are attached on pages 3 to 44 of this response. They include presentations made at HECO's IRP-3 Demand-Side Technical Committee and Advisory Group meetings (pages 3 to 8), Securities and Exchange Commission documents filed for HEI (pages 9 to 42; there were no disclosures relating to lost revenues and utility incentives in 2000), and a Pacific Business News article dated November 19, 2004 (pages 43 to 44).

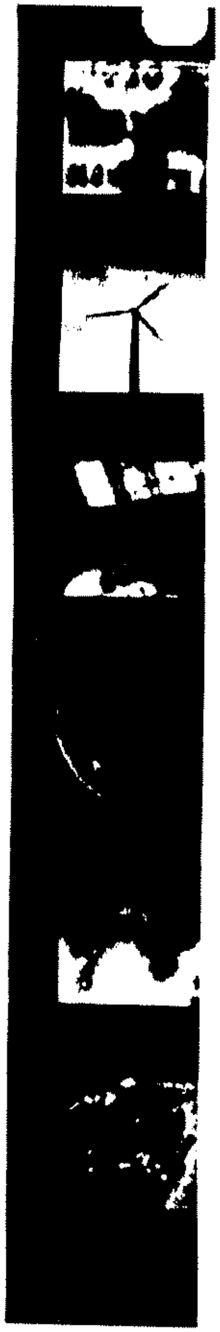
SM programs

test year

Programs

SM programs

est year



Demand Side Management:
An Overview

Rich Barnes, KEMA-XENERGY

Presentation to the Demand-Side Technical Committee

Prepared for
Hawaiian Electric Company
December 1, 2003

nt Programs

Description

anagement Programs

SOP)

orary continuation of C&I DSM programs

case delay
ng by 12 months to a 2005 test year

emand-Side Management Programs

orary continuation of Res DSM programs

case delay
ng by 12 months to a 2005 test year

KEMA

The Renaissance of DSM: 1990 - 1995

- The TRC perspective takes charge.
- Renewed focus on energy efficiency programs
- Key driver: Cost Recovery
  - Shareholder incentives
  - Lost margin recovery
- Potential encouraged cream skimming
- Considerable increase in program evaluation activities to justify cost & incentive recovery
- High emphasis on IRP

Assessment of Hawaii's Energy Efficiency and Demand Response Potential

Phase II – Developing the Energy Efficiency Program Portfolio

Meeting #3: Demand-Side Technical Committee

Greg Wikler– Discussion Leader
Bettina Foster

March 25, 2004

Global Energy Partners, LLC
AN EPRI DMJM+H+N COMPANY

DSM Lost Margin and Shareholder Incentive Mechanisms

- Current arrangement allows HECO to recover program costs and lost margins plus an incentive to encourage greater performance
- Mechanism is critical to maintaining a viable and expanding market for energy efficiency in Hawaii
- Practices at other utilities should be investigated (e.g., California, Iowa, New Jersey)

Global Energy Partners, LLC
AN EPRI, DMJMH+N COMPANY

Hawaiian Elect... Company, Inc.

Demand Side Technical Committee Report to the HECO IRP Advisory Group

May 2004

awaiian Elec Company, Inc.

ide Technical Committee

y Incentives for DSM

nbers Expressed Support for
s (Representative Quotes)

ie Use of Foreign Oil Should Be

ow for the Utility to Earn Rewards for
ner Than Increased Sales"

Use More Alternative Energy Sources
Imports (So) … the Utility Should Be
Using Alternative Energy"

iould Be Compensated for Its Efforts in
rvation"

as to Be Kept Whole If We Want Them
I Programs"

and conditions for obtaining backup and supplemental electric power from the utility when a customer obtains all or part of its electric power from sources other than HELCO.

The timing of a future HELCO rate increase request, if any, to recover costs relating to adding two combustion turbines at Keahole, including the remaining cost of pre-air permit facilities, will depend on future circumstances. See "HELCO power situation" in note (3) of HECO's "Notes to consolidated financial statements."

Regulatory asset related to delayed project costs

In December 1991, HECO filed an application with the PUC for the installation of a nominal 200 MW combined cycle power plant. Due to changes in circumstances, the expected timing for HECO's next generating unit was significantly delayed, and HECO withdrew its application in May 1993. In August 1994, HECO informed the PUC that, consistent with past and then current company practices, the accumulated project costs would be allocated primarily to ongoing active capital projects. The PUC advised HECO to file an application, which it did in February 1995, citing project costs of $5.8 million. The Consumer Advocate objected to the accounting treatment proposed by HECO. To simplify and expedite the proceeding, in September 2000, HECO and the Consumer Advocate reached an agreement on the accounting treatment, subject to PUC approval. Acceptance of the agreement by the parties was without prejudice to any position either of them may take in any subsequent proceeding. Under the agreement, $4.5 million of the $5.8 million total project costs would be amortized to operating expense ratably over a five-year period. In September 2000, HECO adjusted the project costs by $1.3 million to reflect the agreement with the Consumer Advocate, resulting in an after tax write-off of $0.8 million. In September 2001, HECO received PUC approval to amortize $4.5 million ratably over a five-year period, which HECO will begin in October 2001.

Other regulatory matters 9/30/01 Form 10-Q

In October 2001, HECO and the Consumer Advocate finalized an agreement, subject to PUC approval, under which HECO's three commercial and industrial demand-side management (DSM) programs and two residential DSM programs would be continued until HECO's next rate case (which HECO commits under the agreement to file within three years using a 2003 or 2004 test year). The agreement is in lieu of HECO continuing to seek approval of new 5-year DSM programs. Any DSM programs to be in place after HECO's next rate case will be determined as part of the case. Under the agreement, HECO will cap the recovery of lost margins and shareholder incentives if such recovery would cause HECO to exceed its current authorized return on rate base. HECO also agrees it will not pursue the continuation of lost margins recovery through a surcharge mechanism or shareholder incentives in future rate cases. Further, the agreement provides that HELCO and MECO will take the steps necessary to implement any changes made by the PUC with respect to DSM program costs within one year from the time such costs are incorporated into HECO's rates as a result of HECO's next rate case, at which time HELCO and MECO will cease accrual of lost margins and shareholder incentives. Consistent with the time period for the extension, but concludes that an extension is warranted, "under such conditions as the Board may deem advisable." The parties must file any objections to the recommendation by November 30, 2001. The matter will then be set for decision at a hearing before the BLNR.

B. Other regulatory matters 11/15/01 Form 8-K

In October 2001, HECO and the Consumer Advocate finalized agreements, subject to PUC approval, under which HECO's three commercial and industrial demand-side management (DSM) programs and two residential DSM programs would be continued until HECO's next rate case (which HECO commits under the agreement to file within three years using a 2003 or 2004 test year). The agreements for the temporary continuation of HECO's existing DSM programs are in lieu of HECO continuing to seek approval of new 5-year DSM programs. Any DSM programs to be in place after HECO's next rate case will be determined as part of the case. Under the agreements, HECO will cap the recovery of lost margins and shareholder incentives if such recovery would cause HECO to exceed its current authorized return on rate base. HECO also agrees it will not pursue the continuation of lost margins recovery through a surcharge mechanism or shareholder incentives in future rate cases. Further, the agreements provide that HELCO and MECO will take the steps necessary to implement any changes made by the PUC with respect to DSM program costs within one year from the time such costs are incorporated into HECO's rates as a result of HECO's next rate case, at which time HELCO and MECO will cease accrual of lost margins and shareholder incentives. Consistent with the agreements, HELCO and MECO filed requests to continue their existing DSM programs on October 31, 2001. On November 15, 2001, the PUC issued two decisions and orders that, subject to certain reporting requirements and other conditions, approved the stipulations regarding the temporary continuation of the DSM programs until HECO's next rate case.

C. Guam project

On November 27, 2001, HEI issued the following news release:

HAWAIIAN ELECTRIC INDUSTRIES, INC. ANNOUNCES SALE OF GUAM OPERATIONS TO MIRANT

HONOLULU – Hawaiian Electric Industries, Inc. (**NYSE - HE**) today announced the sale of its wholly-owned subsidiary, HEI Power Guam, to Mirant (**NYSE – MIR**) for a nominal profit. The sale was made pursuant to HEI's plan to discontinue its international power operations announced on October 31, 2001.

HEI Power Guam was formed primarily to repair, manage and operate two 25-megawatt (net) units located in Tanguisson, Guam for the Guam Power Authority (GPA). With the sale, Mirant will assume the operations and maintenance of the Tanguisson plant for GPA.

HEI is a diversified holding company. Its core businesses are electric utilities and a bank.

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Item 7. Financial statements and exhibits.

(c) Exhibits.

HEI Exhibit 99	Amendment 2001-1 to the Hawaiian Electric Industries Retirement Savings Plan, for incorporation by reference into Registration Statement on Form S-8 (Registration No. 333-02103)

Generation statistics

The following table contains certain generation statistics as of December 31, 2001 and for the year ended December 31, 2001. The capability available for operation at any given time may be less than the generating capability shown because of capability restrictions or temporary outages for inspection, maintenance, repairs or unforeseen circumstances.

	Island of Oahu-HECO	Island of Maui-MECO	Island of Lanai-MECO	Island of Molokai-MECO	Island of Hawaii-HELCO	Total
Generating and firm purchased capability (MW) at December 31, 2001 [1]						
Conventional oil-fired steam units....	1,160.0	37.6	–	–	69.7	1,267.3
Diesel........	–	96.1	10.4	9.9	38.0	154.4
Combustion turbines (peaking units)	103.0	–	–	–	–	103.0
Combustion turbines........	–	42.4	–	2.2	45.3	89.9
Combined-cycle unit........	–	58.0	–	–	–	58.0
Firm contract power [2]........	406.0	16.0	–	–	108.5	530.5
	1,669.0	250.1	10.4	12.1	261.5	2,203.1
Gross peak demand (MW)........	1,233.0	191.0	5.2	6.5	178.1	1,613.8 [3]
Reserve margin........	35.4%	30.9%	101.9%	87.6%	46.8%	36.5%
Annual load factor........	73.5%	70.7%	65.2%	71.5%	68.9%	72.6% [3]
KWH net generated and purchased (millions)........	7,643.3	1,142.7	28.4	39.1	1,050.5	9,904.0

1 HECO units at normal ratings; MECO and HELCO units at reserve ratings.
2 Nonutility generators (oil-fired except as noted)—HECO: 180 MW (Kalaeloa), 180 MW (AES Hawaii, coal-fired) and 46 MW (refuse-fired); MECO: 16 MW (HC&S, primarily bagasse-fired); HELCO: 28 MW (PGV, geothermal), 22 MW (HCPC, coal-fired) and 58.5 MW (Hamakua Partners).
3 Noncoincident and nonintegrated.

Integrated resource planning and requirements for additional generating capacity 12/31/01 Form 10-K

As a result of a proceeding initiated in 1990, the Public Utilities Commission of the State of Hawaii (PUC) issued an order in 1992 requiring the energy utilities in Hawaii to develop integrated resource plans (IRPs). The goal of integrated resource planning is the identification of demand- and supply-side resources and the integration of these resources for meeting near- and long-term consumer energy needs in an efficient and reliable manner at the lowest reasonable cost. In its 1992 order, the PUC adopted a "framework," which established both the process and the guidelines for developing IRPs. The PUC's framework directs that each plan cover a 20-year planning horizon with a five-year program implementation schedule and states that the planning cycle will be repeated every three years. Under the framework, the PUC may approve, reject or require modifications of the utilities' IRPs.

The framework also states that utilities are entitled to recover all appropriate and reasonable integrated resource planning and implementation costs, including the costs of planning and implementing DSM programs. Under appropriate circumstances, the utilities have been allowed in the past to recover lost margins resulting from DSM programs and earn shareholder incentives. The PUC has approved IRP cost recovery provisions for HECO, MECO and HELCO. Pursuant to the cost recovery provisions, the electric utilities have been allowed to recover through a surcharge the costs for approved DSM programs (including DSM program lost margins and shareholder incentives), and other incremental IRP costs incurred by the utilities and approved by the PUC, to the extent the costs are not included in their base rates.

In October 2001, HECO and the Consumer Advocate finalized agreements, subject to PUC approval, under which HECO's three commercial and industrial DSM programs and two residential DSM programs would be continued until HECO's next rate case (which HECO commits under the agreements to file within three years using a 2003 or 2004 test year). The agreements for the temporary continuation of HECO's existing DSM programs are in lieu of HECO continuing to seek approval of new five-year DSM programs. Any DSM programs to be in place after HECO's next rate case will be determined as part of the case. Under the agreements, HECO will cap the recovery of lost margins and shareholder incentives if such recovery would cause HECO to exceed its current authorized return on rate base. HECO also agrees it will not pursue the continuation of lost margins recovery through a surcharge mechanism or shareholder incentives in future rate cases. Consistent with the agreements, in October 2001, MECO and HELCO filed requests to continue their four existing DSM programs. In November 2001, the PUC issued two decisions and orders (D&O) that, subject to certain reporting requirements and other conditions, approved the agreements regarding the temporary continuation of HECO's five existing DSM programs until HECO's next rate case. In November 2001 (as amended in December 2001), the PUC also issued two D&Os that, subject to certain reporting requirements and other conditions, approved the agreements regarding the temporary continuation of MECO's and HELCO's DSM programs until one year after rates are established in HECO's next rate case. The D&Os also provided for the continued recovery of lost margins and shareholder incentives by MECO and HELCO until rates are established in HECO's next rate case. The D&Os allow MECO and HELCO to request an extension of time for the recovery of lost margins and shareholder incentives for up to one year after rates are established in HECO's next rate case. All of the electric utilities' existing DSM programs are energy efficiency programs designed to reduce the consumption of electricity.

In August 2000, pursuant to a stipulation filed by the electric utilities and the parties in the IRP cost proceedings, the PUC issued an order allowing the electric utilities to begin recovering the 1995 through 1999 incremental IRP costs (over a 12 month period for HECO and a 24 month period for HELCO and MECO), subject to refund with interest, pending the PUC's final D&O approving recovery of each respective year's incremental IRP costs. The Consumer Advocate has objected to the recovery of certain incremental IRP costs incurred during the 1995-1998 period, and the electric utilities have filed responses. Schedules have been established for the filing of positions with respect to the 1999, 2000 and 2001 IRP costs. On September 1, 2000, the electric utilities began recovering 1995 through 1999 incremental IRP costs through a surcharge on customer bills. HECO completed the recovery of its 1995 through 1999 incremental IRP costs in August 2001. MECO and HELCO completed the recovery of their 1995-1996 incremental IRP costs in August 2001. MECO and HELCO are scheduled to complete the recovery of their 1997-1999 incremental IRP costs by August 2002.

The electric utilities began recovering their 2000 incremental IRP costs, subject to refund with interest pending a final D&O, in November 2001. HECO completed the recovery of its 2000 incremental IRP costs in November 2001. MECO and HELCO are scheduled to complete the recovery of their 2000 incremental IRP costs by August 2002. As of December 31, 2001, the amount of revenues the electric utilities recorded for IRP cost recoveries, subject to refund with interest, amounted to $11.9 million. HECO and MECO expect to begin recovering their incremental 2001 IRP costs, subject to refund with interest pending a final D&O, following the filing of actual 2001 costs (which is expected to occur in late March or early April 2002).

In early 2001, the PUC issued its final D&O in the HELCO 2000 test year rate case, in which the PUC concluded that it is appropriate for HELCO to recover its IRP cost through base rates (and included an estimated amount for such costs in HELCO's test year revenue requirements) and to discontinue recovery of incremental IRP costs through the separate surcharge. HELCO will continue to recover its DSM program costs, lost margins and offsetting the impact of decreased pension and other postretirement benefit expenses were more station maintenance and transmission and distribution maintenance expenses. AFUDC for 2000 was 22% higher than 1999 due to a higher base on which AFUDC is calculated.

Recent rate requests

HEI's electric utility subsidiaries initiate Public Utilities Commission of the State of Hawaii (PUC) proceedings from time to time to request electric rate increases to cover rising operating costs (e.g., the cost of purchased power) and the cost of plant and equipment, including the cost of new capital projects to maintain and improve service reliability. As of February 13, 2002, the return on average common equity (ROACE) found by the PUC to be reasonable in the most recent final rate decision for each utility was 11.40% for HECO (decision and order (D&O) issued on December 11, 1995, based on a 1995 test year), 11.50% for HELCO (D&O issued on February 8, 2001, based on a 2000 test year) and 10.94% for Maui Electric Company, Limited (MECO) (amended D&O issued on April 6, 1999, based on a 1999 test year). For 2001, the actual simple average ROACEs (calculated under the rate-making method and reported to the PUC) for HECO, HELCO and MECO were 11.46%, 7.89% and 10.34%, respectively.

HECO has not initiated a rate case for several years, but in 2001 it committed to initiate a rate case within three years, using a 2003 or 2004 test year, as part of the agreement described below under "Other regulatory matters."

The following are summaries of the most recent rate proceedings initiated by HELCO and MECO.

Hawaii Electric Light Company, Inc. In October 1999, HELCO filed a request to increase rates by 9.6%, or $15.5 million in annual revenues, based on a 2000 test year. In early 2001, HELCO received a final D&O from the PUC authorizing an $8.4 million, or 4.9% increase in annual revenues, effective February 15, 2001 and based on an 11.50% ROACE. The order granted HELCO an increase of approximately $2.3 million in annual revenues, in addition to affirming interim increases that took effect in September 2000 ($3.5 million) and January 2001 ($2.6 million). The D&O included in rate base $7.6 million for pre-air permit facilities needed for the delayed Keahole power plant expansion project that the PUC had also found to be used or useful to support the existing generating units at Keahole.

On June 1, 2001, the PUC issued an order approving a new standby service rate schedule rider for HELCO. The standby service rider issue had been bifurcated from the rest of the rate case. The rider provides the rates, terms and conditions for obtaining backup and supplemental electric power from the utility when a customer obtains all or part of its electric power from sources other than HELCO.

The timing of a future HELCO rate increase request to recover costs relating to the delayed Keahole power plant expansion project, i.e., adding two combustion turbines (CT-4 and CT-5) at Keahole, including the remaining cost of pre-air permit facilities, will depend on future circumstances. See "Certain factors that may affect future results and financial condition–Electric utility–Other regulatory and permitting contingencies" below and "HELCO power situation" in Note 3 of the "Notes to Consolidated Financial Statements."

Maui Electric Company, Limited. In January 1998, MECO filed a request to increase rates, based on a 1999 test year, primarily to recover costs relating to the addition of generating unit M17 in late 1998. In November 1998, MECO revised its requested increase to 11.9%, or $16.4 million, in annual revenues, based on a 12.75% ROACE. In April 1999, MECO received an amended final D&O from the PUC which authorized an 8.2%, or $11.3 million, increase in annual revenues, based on a 1999 test year and a 10.94% ROACE.

Other regulatory matters 3/5/02 Form 8-K

In October 2001, HECO and the Consumer Advocate finalized agreements, subject to PUC approval, under which HECO's three commercial and industrial demand-side management (DSM) programs and two residential DSM programs would be continued until HECO's next rate case (which, under the agreements, HECO committed to file within three years). The agreements for the temporary continuation of HECO's existing DSM programs are in lieu of HECO continuing to seek approval of new 5-year DSM programs. Any DSM programs to be in place after HECO's next rate case will be determined as part of the case. Under the agreements, HECO will cap the recovery of lost margins and shareholder incentives if such recovery would cause HECO to exceed its current authorized return on rate base. HECO also agrees it will not pursue the continuation of lost margins recovery through a surcharge mechanism or shareholder incentives in future rate cases. Consistent with the HECO agreements, in October 2001, HELCO and MECO reached agreements with the Consumer Advocate and filed requests to continue their four existing DSM programs. In November 2001, the PUC issued orders (two of which were amended) that, subject to certain reporting requirements and other conditions, approved (1) the agreements regarding the temporary continuation of HECO's five existing DSM programs until HECO's next rate case and (2) the agreements regarding the temporary continuation of HELCO's and MECO's DSM programs until one year after the PUC makes a revenue requirements determination in HECO's next rate case. Under the orders, however, HELCO and MECO are allowed to recover only lost margins and shareholder incentives accrued through the date that interim rates are established in HECO's next rate case, but may request to extend the time of such accrual and recovery for up to one additional year.

Collective bargaining agreements

In August 2000, HECO, HELCO and MECO employees represented by the International Brotherhood of Electrical Workers, AFL-CIO, Local 1260, ratified new collective bargaining agreements covering approximately 62% of the employees of HECO, HELCO and MECO. The new collective bargaining agreements (including benefit agreements) cover a three-year period from November 1, 2000 through October 31, 2003. The main provisions of the agreements include noncompounded wage increases of 2.25% effective November 1, 2000, 2.5% effective November 1, 2001 and 2.5% effective November 1, 2002. The agreements also included increased employee contributions to medical premiums.

Legislation

Congress and the Hawaii legislature periodically consider legislation that could have positive or negative effects on the utilities and their customers. For example, Congress is consid be reasonable in the most recent final rate decision for each utility was 11.40% for HECO (decision and order (D&O) issued on December 11, 1995, based on a 1995 test year), 11.50% for HELCO (D&O issued on February 8, 2001, based on a 2000 test year) and 10.94% for MECO (amended D&O issued on April 6, 1999, based on a 1999 test year). For 2001, the actual simple average ROACE (calculated under the rate-making method and reported to the PUC) for HECO, HELCO and MECO were 11.46%, 7.89% and 10.34%, respectively.

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On June 1, 2001, the PUC issued an order approving a new standby service rate schedule rider for HELCO. The standby service rider issue had been bifurcated from the rest of the rate case. The rider provides the rates, terms and conditions for obtaining backup and supplemental electric power from the utility when a customer obtains all or part of its electric power from sources other than HELCO.

The timing of a future HELCO rate increase request to recover costs relating to the delayed Keahole power plant expansion project, i.e., adding two combustion turbines (CT-4 and CT-5) at Keahole, including the remaining cost of pre-air permit facilities, will depend on future circumstances. See "Certain factors that may affect future results and financial condition-Other regulatory and permitting contingencies" below and "HELCO power situation" in Note 11 of the "Notes to Consolidated Financial Statements."

Maui Electric Company, Limited. In January 1998, MECO filed a request to increase rates, based on a 1999 test year, primarily to recover costs relating to the addition of generating unit M17 in late 1998. In November 1998, MECO revised its requested increase to 11.9%, or $16.4 million, in annual revenues, based on a 12.75% ROACE. In April 1999, MECO received an amended final D&O from the PUC which authorized an 8.2%, or $11.3 million, increase in annual revenues, based on a 1999 test year and a 10.94% ROACE.

Other regulatory matters 3/5/02 From 8-K

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Collective bargaining agreements
In August 2000, HECO, HELCO and MECO employees represented by the International Brotherhood of Electrical Workers, AFL-CIO, Local 1260, ratified new collective bargaining agreements covering approximately 62% of the employees of HECO, HELCO and MECO. The new collective bargaining agreements (including benefit agreements) cover a three-year period from November 1, 2000 through October 31, 2003. The main provisions of the agreements include noncompounded wage increases of 2.25% effective November 1, 2000, 2.5% effective November 1, 2001 and 2.5% effective November 1, 2002. The agreements also included increased employee contributions to medical premiums.

Legislation
Congress and the Hawaii legislature periodically consider legislation that could have positive or negative effects on the utilities and their customers. For example, Congress is considering an energy plan that could increase the domestic supply of oil, as well as increase support for energy conservation programs.

The Hawaii legislature did not consider deregulation in its 2001 session, but passed a law that requires electric utilities to establish "renewables portfolio standard" goals of 7% by December 31, 2003, 8% by December 31, 2005 and 9% by December 31, 2010. HECO, HELCO and MECO are permitted to aggregate their renewable portfolios in order to achieve these goals. Any electric utility whose percentage of sales of electricity represented by renewable energy does not meet these goals will have to report to the PUC and provide an explanation for not meeting the renewables portfolio standard. The PUC could then grant a waiver from the standard or an extension for meeting the standard. The PUC may also provide incentives to encourage electric utilities to exceed the standards or meet the standards earlier, or both, but as yet no such incentives have been proposed. The new law also requires that electric utilities offer net energy metering to solar, wind turbine, biomass or hydroelectric generating systems (or hybrid systems) with a capacity up to 10 kilowatts (i.e., a customer-generator may be a net user or supplier of energy and will make payments to or receive credit from the electric utility accordingly).

HECO and its subsidiaries currently support renewable sources in various ways, including their solar water heating and heat pump programs and their purchased power contracts with nonutility generators using renewable sources (e.g., refuse-fired, geothermal, hydroelectric and wind turbine generating systems). HECO and its subsidiaries continue to initiate and support many renewable energy research and development projects to help develop these technologies (e.g., photovoltaic projects). They are also conducting integrated resource planning to evaluate the use of more renewables. Nevertheless, about 6.9% of electricity sales for 2001 were from renewable resources and the Company believes it may be difficult to increase this percentage, particularly if sales of electricity increase in future years as projected. Thus, at this time, management cannot predict the impact of this law or of proposed legislation on the Company or its customers.

Effects of inflation
U.S. inflation, as measured by the U.S. Consumer Price Index, averaged 1.6 % in 2001, 3.4% in 2000 and 2.2% in 1999. Hawaii inflation, as measured by the Honolulu Consumer Price Index, averaged an estimated 1.2% in 2001, 1.7% in 2000 and 1.0% in 1999. Although the rate of inflation over the past three years has been relatively low compared with the late 1970's and early 1980's, inflation continues to have an impact on the Company's operations.

allowed in final orders. Management cannot predict with certainty when D&Os in pending or future rate cases will be rendered or the amount of any interim or final rate increase that may be granted.

Recent rate requests

HEI's electric utility subsidiaries initiate PUC proceedings from time to time to request electric rate increases to cover rising operating costs (e.g., the cost of purchased power) and the cost of plant and equipment, including the cost of new capital projects to maintain and improve service reliability. As of May 1, 2002, the return on average common equity (ROACE) found by the PUC to be reasonable in the most recent final rate decision for each utility was 11.40% for HECO (D&O issued on December 11, 1995 and based on a 1995 test year), 11.50% for HELCO (D&O issued on February 8, 2001 and based on a 2000 test year) and 10.94% for MECO (amended D&O issued on April 6, 1999 and based on a 1999 test year).

Hawaiian Electric Company, Inc.

HECO has not initiated a rate case for several years, but in 2001 it committed to initiate a rate case within three years, using a 2003 or 2004 test year, as part of the agreement described below under "Other regulatory matters."

Hawaii Electric Light Company, Inc.

In October 1999, HELCO filed a request to increase rates [redacted] requirements determination in HECO's next rate case. Under the orders, however, HELCO and MECO are allowed to recover only lost margins and shareholder incentives accrued through the date that interim rates are established in HECO's next rate case, but may request to extend the time of such accrual and recovery for up to one additional year.

Accounting for the effects of certain types of regulation

In accordance with SFAS No. 71, "Accounting for the Effects of Certain Types of Regulation," the Company's financial statements reflect assets and costs of HECO and its subsidiaries based on current cost-based rate-making regulations. Management believes HECO and its subsidiaries' operations currently satisfy the SFAS No. 71 criteria. However, if events or circumstances should change so that those criteria are no longer satisfied, management believes that a material adverse effect on the Company's results of operations, financial position or liquidity may result. As of March 31, 2002, HECO's consolidated regulatory assets amounted to $110 million.

Legislation

Congress and the Hawaii legislature periodically consider legislation that could have positive or negative effects on the utilities and their customers. For example, Congress is considering an energy plan that could increase the domestic supply of oil, as well as increase support for energy conservation programs.

The Hawaii legislature did not consider deregulation in its 2002 session, but did consider legislation to prohibit standby charges by utilities, mandate the undergrounding of utility lines, establish green-marketing programs and institute a carbon tax on utilities, among other proposals. None of these proposals was adopted by the legislature.

Bank

	Three months ended March 31,		%	
(in thousands)	2002	2001	change	Primary reason(s) for significant change
Revenues	$98,842	$115,754	(15)	Lower interest income as a result of lower weighted-average yields and a lower average loan balance, partly offset by higher other income (including higher fee income)
Operating income.....	22,171	20,149	10	Higher net interest and other income, partly offset by higher general and administrative expenses and provision for loan losses
Net income	13,351	11,875	12	Higher operating income
Interest rate spread...	3.27%	3.01%	9	136 basis points decrease in the weighted-average yield on interest-earning assets, more than offset by a 162 basis points decrease in the weighted-average rate on interest-bearing liabilities

Earnings of ASB depend primarily on net interest income. ASB's loan volumes and yields are affected by market interest rates, competition, demand for real estate financing, availability of funds and management's responses to these factors. Advances from the Federal Home Loan Bank (FHLB) of Seattle and securities sold under agreements to repurchase continue to be significant sources of funds that have higher costs than deposits. Other factors affecting ASB's operating results include sales of securities available for sale, fee income, provision for loan losses and expenses from operations.

ASB's interest rate spread—the difference between the weighted-average yield on interest-earning assets and the weighted-average rate on interest-bearing liabilities—increased 9%. Comparing first quarter 2002 to the same

PUC Commissioners

In July 2002, Commissioner Dennis R. Yamada retired and Commissioner Wayne H. Kimura became the Chairman of the PUC. Continuing to serve is Commissioner Janet E. Kawelo. A third PUC Commissioner is yet to be appointed, and would be subject to Senate confirmation.

Other regulatory matters 6/30/02 Form 10-Q

In October 2001, HECO and the Consumer Advocate finalized agreements, subject to PUC approval, under which HECO's three commercial and industrial demand-side management (DSM) programs and two residential DSM programs would be continued until HECO's next rate case (which, under the agreements, HECO committed to file using a 2003 or 2004 test year). The agreements for the temporary continuation of HECO's existing DSM programs are in lieu of HECO continuing to seek approval of new 5-year DSM programs. Any DSM programs to be in place after HECO's next rate case will be determined as part of the case. Under the agreements, HECO will cap the recovery of lost margins and shareholder incentives if such recovery would cause HECO to exceed its current authorized return on rate base. HECO also agrees it will not pursue the continuation of lost margins recovery through a surcharge mechanism or shareholder incentives in future rate cases. Consistent with the HECO agreements, in October 2001, HELCO and MECO reached agreements with the Consumer Advocate and filed requests to continue their four existing DSM programs. In November 2001, the PUC issued orders (one of which was later amended) that, subject to certain reporting requirements and other conditions, approved (1) the agreements regarding the temporary continuation of HECO's five existing DSM programs until HECO's next rate case and (2) the agreements regarding the temporary continuation of HELCO's and MECO's DSM programs until one year after the PUC makes a revenue requirements determination in HECO's next rate case. Under the orders, however, HELCO and MECO are allowed to recover only lost margins and shareholder incentives accrued through the date that interim rates are established in HECO's next rate case, but may request to extend the time of such accrual and recovery for up to one additional year.

Legislation

Congress and the Hawaii legislature periodically consider legislation that could have positive or negative effects on the utilities and their customers. For example, Congress is attempting to reconcile substantially different House and Senate versions of an energy bill. Outcomes could range from an increased supply of domestic oil to federal mandates for renewable energy.

The Hawaii legislature did not consider deregulation in its 2002 session, but did consider legislation to prohibit standby charges by utilities, require the undergrounding of utility lines, establish "green" marketing programs and institute a carbon tax on utilities, among other proposals. None of these proposals was adopted by the legislature.

proposed changes coincide with the effective date of the rates established in HECO's next rate case proceeding so that HECO's financial results would not be negatively impacted by the depreciation rates and method ultimately approved by the PUC.

Hawaii Electric Light Company, Inc.

In October 1999, HELCO filed a request to increase rates by 9.6%, or $15.5 million in annual revenues, based on a 2000 test year.

In early 2001, HELCO received a final D&O from the PUC authorizing an $8.4 million, or 4.9% increase in annual revenues, effective February 15, 2001 and based on an [illegible]

Demand-side management programs - lost margins and shareholder incentives

HECO, HELCO and MECO's energy efficiency DSM programs, currently approved by the PUC, provide for the recovery of lost margins and the earning of shareholder incentives.

Lost margins collected are calculated prospectively based on the programs' forecasted levels of participation, and are subject to two adjustments based on (1) the actual level of participation and (2) the results of impact evaluation reports. The difference between the adjusted lost margins and the previously collected lost margins are subject to refund or recovery, with any over or under collection accruing interest at HECO, HELCO, or MECO's authorized rate of return on rate base. HECO, HELCO and MECO plan to file the impact evaluation report for the 2000-2002 period with the PUC in the first quarter of 2004 and adjust the lost margin recovery as required. Past adjustments required for lost margins have not had a material effect on HECO, HELCO or MECO's financial condition, results of operations or liquidity.

Shareholder incentives are calculated and collected retrospectively based on the programs' actual levels of participation for the prior year. Beginning in 2001, shareholder incentives collected are subject to retroactive adjustment based on the results of impact evaluation reports, similar to the adjustment process for lost margins.

Legislation

Congress and the Hawaii legislature periodically consider legislation that could have positive or negative effects on the utilities and their customers. For example, Congress is attempting to reconcile substantially different House and Senate versions of an energy bill. Outcomes could range from an increased supply of domestic oil to federal mandates for renewable energy.

The Hawaii legislature did not consider deregulation in its 2002 session, but did consider legislation to prohibit standby charges by utilities, require the undergrounding of utility lines, require the utilities to establish "green" arketing programs and institute a carbon tax on utilities, among other proposals. The legislature did not adopt ese proposals.

Bank

	Three months ended September 30,			
($ in thousands)	2002	2001	% change	Primary reason(s) for significant change
Revenues...............	$99,722	$108,034	(8)	Lower interest income as a result of a lower weighted-average yield on interest-earning assets, partly offset by higher other income, including higher fee income
Operating income ...	24,566	19,488	26	Higher net interest and other income and lower provision for loan losses, partly offset by higher expenses, including higher compensation, consulting, data processing and occupancy and equipment expenses. Also, in 2002, goodwill is no longer being amortized.
Net income.............	14,652	11,072	32	Higher operating income
Interest rate spread.	3.28%	3.08%	6	86 basis points decrease in the weighted-average yield on interest-earning assets, more than offset by a 106 basis points decrease in the weighted-average rate on interest-bearing liabilities

Recent rate requests

HECO, HELCO and MECO initiate PUC proceedings from time to time to request electric rate increases to cover rising operating costs (e.g. the cost of purchased power) and the cost of plant and equipment, including the cost of new capital projects to maintain and improve service reliability. As of February 12, 2003, the return on average common equity (ROACE) found by the PUC to be reasonable in the most recent final rate decision for each utility was 11.40% for HECO (decision and order (D&O) issued on December 11, 1995, based on a 1995 test year), 11.50% for HELCO (D&O issued on February 8, 2001, based on a 2000 test year) and 10.94% for MECO (amended D&O issued on April 6, 1999, based on a 1999 test year). For 2002, the actual simple average ROACEs (calculated under the rate-making method and reported to the PUC) for HECO, HELCO and MECO were 11.33%, 7.52% and 10.30%, respectively.

Hawaiian Electric Company, Inc. HECO has not initiated a rate case for several years, but in 2001 it committed to initiate a rate case within three years, using a 2003 or 2004 test year, as part of the agreement described below under "Other regulatory matters, Demand-side management programs – agreements with the Consumer Advocate." In October 2002, HECO filed an application with the PUC for approval to change its depreciation rates and to change to vintage amortization accounting for selected plant accounts, which changes would have amounted to an estimated $4.2 million, or 6.3%, increase in depreciation expense based on a study of depreciation expense for 2000. In its application, HECO requested that the effective date of the proposed changes coincide with the effective date of the rates established in HECO's next rate case proceeding so that HECO's financial results would not be negatively impacted by the depreciation rates and method ultimately approved by the PUC.

Hawaii Electric Light Company, Inc. In early 2001, HELCO received a final D&O from the PUC authorizing an $8.4 million, or 4.9% increase in annual revenues, effective February 15, 2001 and based on an 11.50% ROACE. The D&O included in rate base $7.6 million for pre-air permit facilities needed for the delayed Keahole power plant expansion project that the PUC had also found to be used or useful to support the existing generating units at Keahole. The timing of a future HELCO rate increase request to recover costs relating to the delayed Keahole power plant expansion project, i.e., adding two combustion turbines (CT-4 and CT-5) at Keahole, including the remaining cost of pre-air permit facilities, will depend on future circumstances. See "Certain factors that may affect future results and financial condition–Other regulatory and permitting contingencies" and "HELCO power situation" in Note 11 of the "Notes to Consolidated Financial Statements."

On June 1, 2001, the PUC issued an order approving a new standby service rate schedule rider for HELCO. The standby service rider issue had been bifurcated from the rest of the rate case. The rider provides the rates, terms and conditions for obtaining backup and supplemental electric power from the utility when a customer obtains all or part of its electric power from sources other than HELCO.

Other regulatory matters 2/25/03 Form 8-K

Demand-side management programs - lost margins and shareholder incentives. HECO, HELCO and MECO's energy efficiency demand-side management (DSM) programs, currently approved by the PUC, provide for the recovery of lost margins and the earning of shareholder incentives.

Lost margins are accrued and collected prospectively based on the programs' forecasted levels of participation, and are subject to two adjustments based on (1) the actual level of participation and (2) the results of impact evaluation reports. The difference between the adjusted lost margins and the previously collected lost margins are subject to refund or recovery, with any over or under collection accruing interest at HECO, HELCO, or MECO's authorized rate of return on rate base. HECO, HELCO and MECO plan to file the impact evaluation report for the 2000-2002 period with the PUC in the fourth quarter of 2004 and adjust the lost margin recovery as required. Past adjustments required for lost margins have not had a material effect on HECO, HELCO or MECO's financial statements.

Shareholder incentives are accrued currently and collected retrospectively based on the programs' actual levels of participation for the prior year. Beginning in 2001, shareholder incentives collected are subject to retroactive adjustment based on the results of impact evaluation reports, similar to the adjustment process for lost margins.

Demand-side management programs – agreements with the Consumer Advocate. In October 2001, HECO and the Consumer Advocate finalized agreements, subject to PUC approval, under which HECO's three commercial and industrial DSM programs and two residential DSM programs would be continued until HECO's next rate case, which, under the agreements, HECO committed to file using a 2003 or 2004 test year and following the PUC's rules for determining the test year. The agreements for the temporary continuation of HECO's existing DSM programs were in lieu of HECO continuing to seek approval of new 5-year DSM programs. Any DSM programs to be in place after HECO's next rate case will be determined as part of the case. Under the agreements, HECO will cap the recovery of lost margins and shareholder incentives if such recovery would cause HECO to exceed its current authorized return on rate base. HECO also agreed it will not pursue the continuation of lost margins recovery and shareholder incentives through a surcharge mechanism in future rate cases. Consistent with the HECO agreements, in October 2001, HELCO and MECO reached agreements with the Consumer Advocate and filed requests to continue their four existing DSM programs. In November 2001, the PUC issued orders (one of which was later amended) that, subject to certain reporting requirements and other conditions, approved (1) the agreements regarding the temporary continuation of HECO's five existing DSM programs until HECO's next rate case and (2) the agreements regarding the temporary continuation of HELCO's and MECO's DSM programs until one year after the PUC makes a revenue requirements determination in HECO's next rate case. Under the orders, however, HELCO and MECO are allowed to recover only lost margins and shareholder incentives accrued through the date that interim rates are established in HECO's next rate case, but may request to extend the time of such accrual and recovery for up to one additional year. In 2002, MECO's revenues from shareholder incentives were $0.7 million lower than the amount that would have been recorded if MECO had not agreed to cap such incentives when its authorized return on rate base was exceeded. Also in 2002, HELCO slightly exceeded its authorized return on rate base. If an adjustment is required due to the higher rate of return, HELCO may need to reduce its recorded shareholder incentives by approximately $30,000. In 2002, HECO did not exceed its authorized return on rate base.

Collective bargaining agreements

In August 2000, HECO, HELCO and MECO employees represented by the International Brotherhood of energy costs ($9 million). The increase in KWH sales was primarily due to an increase in the number of customers and warmer temperatures, which typically result in higher air conditioning usage. Through August 2001, KWH sales were up 1.6%. However, declining tourism and the weakened economy after the September 11, 2001 terrorist attacks caused a 0.4% decrease in KWH sales in the fourth quarter compared to the same period last year. Operating income for 2001 was comparable to 2000. Fuel oil expense decreased 4% due primarily to fewer KWHs generated. Purchased power expense increased 9% due primarily to higher purchased capacity payments resulting from increased capacity (including a new IPP in August 2000), higher availability and more KWHs purchased, partly offset by lower energy prices. Other expenses were flat reflecting a 6% decrease in maintenance expense, offset by a 1% increase in other operation expense, a 2% increase in depreciation expense and a 1% increase in taxes, other than income taxes. AFUDC for 2001 was 22% lower than 2000 due to a lower base on which AFUDC is calculated. Interest expense decreased 4% from 2000 due to lower short-term borrowings and lower interest rates.

Recent rate requests

HEI's electric utility subsidiaries initiate PUC proceedings from time to time to request electric rate increases to cover rising operating costs (e.g., the cost of purchased power) and the cost of plant and equipment, including the cost of new capital projects to maintain and improve service reliability. As of February 12, 2003, the return on average common equity (ROACE) found by the PUC to be reasonable in the most recent final rate decision for each utility was 11.40% for HECO (decision and order (D&O) issued on December 11, 1995, based on a 1995 test year), 11.50% for HELCO (D&O issued on February 8, 2001, based on a 2000 test year) and 10.94% for Maui Electric Company, Limited (MECO) (amended D&O issued on April 6, 1999, based on a 1999 test year). For 2002, the actual simple average ROACEs (calculated under the rate-making method and reported to the PUC) for HECO, HELCO and MECO were 11.33%, 7.52% and 10.30%, respectively.

Hawaiian Electric Company, Inc. HECO has not initiated a rate case for several years, but in 2001 it committed to initiate a rate case within three years, using a 2003 or 2004 test year, as part of the agreement described below under "Other regulatory matters, Demand-side management programs – agreements with the Consumer Advocate." In October 2002, HECO filed an application with the PUC for approval to change its depreciation rates and to change to vintage amortization accounting for selected plant accounts, which changes would have amounted to an estimated $4.2 million, or 6.3%, increase in depreciation expense based on a study of depreciation expense for 2000. In its application, HECO requested that the effective date of the proposed changes coincide with the effective date of the rates established in HECO's next rate case proceeding so that HECO's financial results would not be negatively impacted by the depreciation rates and method ultimately approved by the PUC.

Hawaii Electric Light Company, Inc. In early 2001, HELCO received a final D&O from the PUC authorizing an $8.4 million, or 4.9% increase in annual revenues, effective February 15, 2001 and based on an 11.50% ROACE. The D&O included in rate base $7.6 million for pre-air permit facilities needed for the delayed Keahole power plant expansion project that the PUC had also found to be used or useful to support the existing generating units at Keahole. The timing of a future HELCO rate increase request to recover costs relating to the delayed Keahole power plant expansion project, i.e., adding two combustion turbines (CT-4 and CT-5) at Keahole, including the remaining cost of pre-air permit facilities, will depend on future circumstances. See "Certain factors that may affect future results and financial condition–Electric utility–Other regulatory and permitting contingencies" and "HELCO power situation" in Note 3 of the "Notes to Consolidated Financial Statements."

On June 1, 2001, the PUC issued an order approving a new standby service rate schedule rider for HELCO. The standby service rider issue had been bifurcated from the rest of the rate case. The rider provides the rates, terms and conditions for obtaining backup and supplemental electric power from the utility when a customer obtains all or part of its electric power from sources other than HELCO.

Other regulatory matters 2/25/03 Form 8-K

Demand-side management programs - lost margins and shareholder incentives. HECO, HELCO and MECO's energy efficiency demand-side management (DSM) programs, currently approved by the PUC, provide for the recovery of lost margins and the earning of shareholder incentives.

Lost margins are accrued and collected prospectively based on the programs' forecasted levels of participation, and are subject to two adjustments based on (1) the actual level of participation and (2) the results of impact evaluation reports. The difference between the adjusted lost margins and the previously collected lost margins are subject to refund or recovery, with any over or under collection accruing interest at HECO, HELCO, or MECO's authorized rate of return on rate base. HECO, HELCO and MECO plan to file the impact evaluation report for the 2000-2002 period with the PUC in the fourth quarter of 2004 and adjust the lost margin recovery as required. Past adjustments required for lost margins have not had a material effect on HECO, HELCO or MECO's financial statements.

Shareholder incentives are accrued currently and collected retrospectively based on the programs' actual levels of participation for the prior year. Beginning in 2001, shareholder incentives collected are subject to retroactive adjustment based on the results of impact evaluation reports, similar to the adjustment process for lost margins.

Demand-side management programs – agreements with the Consumer Advocate. In October 2001, HECO and the Consumer Advocate finalized agreements, subject to PUC approval, under which HECO's three commercial and industrial DSM programs and two residential DSM programs would be continued until HECO's next rate case, which, under the agreements, HECO committed to file using a 2003 or 2004 test year and following the PUC's rules for determining the test year. The agreements for the temporary continuation of HECO's existing DSM programs were in lieu of HECO continuing to seek approval of new 5-year DSM programs. Any DSM programs to be in place after HECO's next rate case will be determined as part of the case. Under the agreements, HECO will cap the recovery of lost margins and shareholder incentives if such recovery would cause HECO to exceed its current authorized return on rate base. HECO also agreed it will not pursue the continuation of lost margins recovery and shareholder incentives through a surcharge mechanism in future rate cases. Consistent with the HECO agreements, in October 2001, HELCO and MECO reached agreements with the Consumer Advocate and filed requests to continue their four existing DSM programs. In November 2001, the PUC issued orders (one of which was later amended) that, subject to certain reporting requirements and other conditions, approved (1) the agreements regarding the temporary continuation of HECO's five existing DSM programs until HECO's next rate case and (2) the agreements regarding the temporary continuation of HELCO's and MECO's DSM programs until one year after the PUC makes a revenue requirements determination in HECO's next rate case. Under the orders, however, HELCO and MECO are allowed to recover only lost margins and shareholder incentives accrued through the date that interim rates are established in HECO's next rate case, but may request to extend the time of such accrual and recovery for up to one additional year. In 2002, MECO's revenues from shareholder incentives were $0.7 million lower than the amount that would have been recorded if MECO had not agreed to cap such incentives when its authorized return on rate base was exceeded. Also in 2002, HELCO slightly exceeded its authorized return on rate base. If an adjustment is required due to the higher rate of return, HELCO may need to reduce its recorded shareholder incentives by approximately $30,000. In 2002, HECO did not exceed its authorized return on rate base.

Collective bargaining agreements

In August 2000, HECO, HELCO and MECO employees represented by the International Brotherhood of Electrical Workers, AFL-CIO, Local 1260, ratified collective bargaining agreements covering approximately 62% of the employees of HECO, HELCO and MECO. The collective bargaining agreements (including benefit agreements) cover a three-year period from November 1, 2000 through October 31, 2003 and expire at midnight on October 31, 2003. The main provisions of the agreements include noncompounded wage increases of 2.25% effective November 1, 2000, 2.5% effective November 1, 2001 and 2.5% effective November 1, 2002. The agreements also included increased employee contributions to medical premiums. The electric utilities expect to begin negotiations for new collective bargaining agreements in the third quarter of 2003.

Legislation

Congress and the Hawaii legislature periodically consider legislation that could have positive or negative effects on the utilities and their customers. The 2003 Hawaii legislature is considering measures that would undertake a comprehensive audit of Hawaii's electric utility regulatory policies, energy policies and support for reducing Hawaii's dependence on imported petroleum for electrical generation. The legislature is also considering a measure to remove the cap for net energy metering. Management cannot predict whether these proposals will be enacted into law.

In its 2001 session, the Hawaii legislature passed a law establishing "renewable portfolio standard" goals for electric utilities of 7% by December 31, 2003, 8% by December 31, 2005 and 9% by December 31, 2010. HECO,

Most recent rate requests

HEI's electric utility subsidiaries initiate PUC proceedings from time to time to request electric rate increases to cover rising operating costs (e.g., the cost of purchased power) and the cost of plant and equipment, including the cost of new capital projects to maintain and improve service reliability. As of May 1, 2003, the return on average common equity (ROACE) found by the PUC to be reasonable in the most recent final rate decision for each utility was 11.40% for HECO (D&O issued on December 11, 1995, based on a 1995 test year), 11.50% for HELCO (D&O issued on February 8, 2001, based on a 2000 test year) and 10.94% for MECO (amended D&O issued on April 6, 1999, based on a 1999 test year). For 2002, the actual simple average ROACEs (calculated under the rate-making method and reported to the PUC) for HECO, HELCO and MECO were 11.33%, 7.52% and 10.30%, respectively.

As of May 1, 2003, the return on average rate base (ROR) found by the PUC to be reasonable in the most recent final rate decision for each utility was 9.16% for HECO (D&O issued on December 11, 1995, based on a 1995 test year), 9.14% for HELCO (D&O issued on February 8, 2001, based on a 2000 test year) and 8.83% for MECO (amended D&O issued on April 6, 1999, based on a 1999 test year). For 2002, the actual simple average RORs (calculated under the rate-making method and reported to the PUC) for HECO, HELCO and MECO were 8.94%, 9.15% and 8.83%, respectively.

Hawaiian Electric Company, Inc. HECO has not initiated a rate case for several years, but in 2001 it committed to initiate a rate case within three years, using a 2003 or 2004 test year, as part of the agreement described below under "Other regulatory matters, Demand-side management programs – agreements with the Consumer Advocate."

Hawaii Electric Light Company, Inc. In early 2001, HELCO received a final D&O from the PUC authorizing an $8.4 million, or 4.9% increase in annual revenues, effective February 15, 2001 and based on an 11.50% ROACE. The D&O included in rate base $7.6 million for pre-air permit facilities needed for the delayed Keahole power plant expansion project that the PUC had also found to be used or useful to support the existing generating units at Keahole. The timing of a future HELCO rate increase request to recover costs relating to the delayed Keahole power plant expansion project, i.e., adding two combustion turbines (CT-4 and CT-5) at Keahole, including the remaining cost of pre-air permit facilities, will depend on future circumstances. See "HELCO power situation" in note (4) of HECO's "Notes to Consolidated Financial Statements."

On June 1, 2001, the PUC issued an order approving a new standby service rate schedule rider for HELCO. The standby service rider issue had been bifurcated from the rest of the rate case. The rider provides the rates, terms and conditions for obtaining backup and supplemental electric power from the utility when a customer obtains all or part of its electric power from sources other than HELCO.

Other regulatory matters 3/31/03 Form 10-Q

Demand-side management programs - lost margins and shareholder incentives. HECO, HELCO and MECO's energy efficiency demand-side management (DSM) programs, currently approved by the PUC, provide for the recovery of lost margins and the earning of shareholder incentives.

Lost margins are accrued and collected prospectively based on the programs' forecast levels of participation, and are subject to two adjustments based on (1) the actual level of participation and (2) the results of impact evaluation reports. The difference between the adjusted lost margins and the previously collected lost margins are subject to refund or recovery, with any over or under collection accruing interest at HECO, HELCO, or MECO's authorized rate of return on rate base. HECO, HELCO and MECO plan to file the impact evaluation report for the 2000-2002 period with the PUC in the fourth quarter of 2004 and adjust the lost margin recovery as required. Past adjustments required for lost margins have not had a material effect on HECO, HELCO or MECO's financial statements.

Shareholder incentives are accrued currently and collected retrospectively based on the programs' actual levels of participation for the prior year. Beginning in 2001, shareholder incentives collected are subject to retroactive adjustment based on the results of impact evaluation reports, similar to the adjustment process for lost margins.

Demand-side management programs – agreements with the Consumer Advocate. In October 2001, HECO and the Consumer Advocate finalized agreements, subject to PUC approval, under which HECO's three commercial and industrial DSM programs and two residential DSM programs would be continued until HECO's next rate case, which, under the agreements, HECO committed to file using a 2003 or 2004 test year and following the PUC's rules for determining the test year. The agreements for the temporary continuation of HECO's existing DSM programs were in lieu of HECO continuing to seek approval of new 5-year DSM programs. Any DSM programs to be in place after HECO's next rate case will be determined as part of the case. Under the agreements, HECO will cap the recovery of lost margins and shareholder incentives if such recovery would cause HECO to exceed its current authorized return on rate base. HECO also agreed it will not pursue the continuation of lost margins recovery and shareholder incentives through a surcharge mechanism in future rate cases. Consistent with the HECO agreements, in October 2001, HELCO and MECO reached agreements with the Consumer Advocate and filed requests to continue their four existing DSM programs. In November 2001, the PUC issued orders (one of which was later amended) that, subject to certain reporting requirements and other conditions, approved (1) the agreements regarding the temporary continuation of HECO's five existing DSM programs until HECO's next rate case and (2) the agreements regarding the temporary continuation of HELCO's and MECO's DSM programs until one year after the PUC makes a revenue requirements determination in HECO's next rate case. Under the orders, however, HELCO and MECO are allowed to recover only lost margins and shareholder incentives accrued through the date that interim rates are established in HECO's next rate case, but may request to extend the time of such accrual and recovery for up to one additional year. In 2002, MECO's revenues from shareholder incentives were $0.7 million lower than the amount that would have been recorded if MECO had not agreed to cap such incentives when its authorized return on rate base was exceeded. Also in 2002, HELCO slightly exceeded its authorized return on rate base resulting in a reduction to shareholders incentives of approximately $31,000, which HELCO recorded in January 2003. In 2002, HECO did not exceed its authorized return on rate base.

PUC Commissioners. Carlito Caliboso has been appointed Chairman of the PUC effective April 30, 2003. Mr. Caliboso is an attorney and was in private practice prior to his appointment. Continuing to serve on the PUC is Commissioner Wayne H. Kimura, who served as Chairman from July 2002 to April 2003 and Commissioner Janet E. Kawelo.

Nonutility generation

In March 1988, HECO entered into a PPA with AES Barbers Point, Inc. (now known as AES Hawaii), a Hawaii-based, indirect subsidiary of The AES Corporation. The agreement with AES Hawaii, as amended in August 1989, provides that, for a period of 30 years beginning September 1992, HECO will purchase 180 MW of firm capacity. Under the amended PPA, AES Hawaii must obtain certain consents from HECO prior to entering into any arrangement to refinance the facility. AES Hawaii has proposed a possible refinancing of the facility, and HECO and AES Hawaii have reached conceptual agreement on the terms upon which HECO is willing to consent to the proposed refinancing. The terms contemplate that HECO will receive consideration for its consent, primarily in the form of a PPA amendment that will reduce the cost of power supplied to HECO pursuant to the PPA. The benefit of the power cost reduction, totaling approximately $2.9 million annually, will be passed on to ratepayers through a reduction in rates. AES Hawaii also is granting HECO an option, subject to certain conditions, to acquire an interest in portions of the AES Hawaii facility site that are not needed for the existing plant operations, and which potentially could be used for the development of another coal-fired facility. The PPA amendment, the option and HECO's consent to the refinancing are subject to several conditions, including PUC approval of the amendment, agreement on the documents providing HECO's consent and its subordinated security interest in the facility after the refinancing, and completion of the proposed refinancing arrangements by AES Hawaii. HECO has submitted an application to the PUC requesting approval of the PPA amendment.

Legislation

Congress and the Hawaii legislature periodically consider legislation that could have positive or negative effects on the utilities and their customers. The 2003 Hawaii legislature considered measures that would undertake a comprehensive audit of Hawaii's electric utility regulatory policies, energy policies and support for reducing Hawaii's dependence on imported petroleum for electrical generation, and a measure to remove the cap on the amount of net energy metering the utilities would be required to make available to eligible customers. These measures were not enacted into law. The legislature did, however, pass a more restricted bill calling for a management audit of the PUC. Also, the legislature passed a law, which takes effect on July 1, 2003, that requires employers who have at least 100 employees to allow their employees to use up to 10 days of their compensated sick leave per year to care

..eahole. The timing of a future HELCO rate increase request to recover costs relating to the delayed Keahole power plant expansion project, i.e., adding two combustion turbines (CT-4 and CT-5) at Keahole, including the remaining cost of pre-air permit facilities, will depend on future circumstances. See "HELCO power situation" in note (4) of HECO's "Notes to Consolidated Financial Statements."

On June 1, 2001, the PUC issued an order approving a new standby service rate schedule rider for HELCO. The standby service rider issue had been bifurcated from the rest of the rate case. The rider provides the rates, terms and conditions for obtaining backup and supplemental electric power from the utility when a customer obtains all or part of its electric power from sources other than HELCO.

Other regulatory matters 6/30/03 Form 10-Q

Demand-side management programs - lost margins and shareholder incentives. HECO, HELCO and MECO's energy efficiency demand-side management (DSM) programs, currently approved by the PUC, provide for the recovery of lost margins and the earning of shareholder incentives.

agreement has not been finalized since there are two other parties in addition to HECO and the Consumer Advocate with whom the agreement must be discussed. The other components of the existing agreements, as approved by the PUC, would be continued under the proposed new agreements

Nonutility generation

See "Nonutility generation" in note (4) in HECO's "Notes to consolidated financial statements."

Collective bargaining agreements

The current collective bargaining agreements of HECO, HELCO and MECO with Local 1260 of the IBEW, AFL-CIO, for Unit 8 expire on October 31, 2003. Contract negotiations are expected to commence in late August 2003. Unit 8 represents 55% of HECO employees, 73% of HELCO employees and 71% of MECO employees. Should the IBEW not reach agreements with HECO, HELCO and MECO in a timely manner upon the expiration of the existing agreements, HECO and its subsidiaries' results of operations could be adversely affected.

Legislation

Congress and the Hawaii legislature periodically consider legislation that could have positive or negative effects on the utilities and their customers. The 2003 Hawaii legislature considered measures that would undertake a comprehensive audit of Hawaii's electric utility regulatory policies, energy policies and support for reducing Hawaii's dependence on imported petroleum for electrical generation, and a measure to remove the cap on the amount of net energy metering the utilities would be required to make available to eligible customers. These measures were not enacted into law. The legislature did, however, pass a more restricted bill calling for a management audit of the PUC. Also, the legislature passed a law, which took effect on July 1, 2003, that required employers who have at least 100 employees to allow their employees to use up to 10 days of their compensated sick leave per year to care for a sick family member. On June 26, 2003, the Governor signed into law the Hawaii State tax credit for renewable energy, which extends the existing tax credit of 35% of the cost of residential solar water heating (up to $1,750) until at least 2008.

In its 2001 session, the Hawaii legislature passed a law establishing "renewable portfolio standard" goals for electric utilities of 7% by December 31, 2003, 8% by December 31, 2005 and 9% by December 31, 2010. HECO, HELCO and MECO are permitted to aggregate their renewable portfolios in order to achieve these goals. Any electric utility whose percentage of sales of electricity represented by renewable energy does not meet these goals will have to report to the PUC and provide an explanation for not meeting the renewables portfolio standard. The PUC could then grant a waiver from the standard or an extension for meeting the standard. The PUC may also provide incentives to encourage electric utilities to exceed the standards or meet the standards earlier, or both, but as yet no such incentives have been proposed. The law also requires that electric utilities offer net energy metering to solar, wind turbine, biomass or hydroelectric generating systems (or hybrid systems) with a capacity up to 10 kilowatts (i.e., a customer-generator may be a net user or supplier of energy and will make payments to or receive credits from the electric utility accordingly).

The electric utilities currently support renewable sources in various ways, including their solar water heating and heat pump programs and their purchased power contracts with nonutility generators using renewable sources (e.g., refuse-fired, geothermal, hydroelectric and wind turbine generating systems). The electric utilities continue to initiate and support many renewable energy research and development projects to help develop these technologies (e.g., photovoltaic projects). They are also conducting integrated resource planning to evaluate the use of more renewables and, in December 2002, HECO formed a subsidiary, Renewable Hawaii, Inc., to invest in renewable energy projects. In May 2003, Renewable Hawaii, Inc. (RHI) solicited competitive proposals (due August 22, 2003) for investment opportunities in projects (1 MW or larger) to supply renewable energy on the island of Oahu. RHI is seeking to take a passive, minority interest in such projects to help stimulate the addition of cost-effective, commercially viable renewable energy generation in the state of Hawaii. About 6.8% of electricity sales for 2002 were from renewable resources (as defined under the renewable portfolio standard law). Despite their efforts, the electric utilities believe it may be difficult to increase this percentage to the percentages targeted in the 2001 Hawaii legislation, particularly if sales of electricity increase in future years as projected. Thus, at this time, management cannot predict the impact of this law or of other proposed congressional and Hawaii legislation on the utilities or their customers.

Item 5. Other Events 8/25/03 Form 8-K

Demand-side management programs – agreements with the Consumer Advocate

In October 2001, HECO and the Consumer Advocate finalized agreements, subject to Public Utilities Commission of the State of Hawaii (PUC) approval, under which HECO's three commercial and industrial demand-side management (DSM) programs and two residential DSM programs would be continued until HECO's next rate case, which, under the agreements, HECO committed to file using a 2003 or 2004 test year and following the PUC's rules for determining the test year. The PUC rules require that an application be filed between July and December 2003 in order to use a 2004 test year. The agreements for the temporary continuation of HECO's existing DSM programs were in lieu of HECO continuing to seek approval of new 5-year DSM programs. Any DSM programs to be in place after HECO's next rate case will be determined as part of the case. Under the agreements, HECO will cap the recovery of lost margins and shareholder incentives if such recovery would cause HECO to exceed its current authorized return on rate base. HECO also agreed it will not pursue the continuation of lost margins recovery and shareholder incentives through a surcharge mechanism in future rate cases. Consistent with the HECO agreements, in October 2001, Hawaii Electric Light Company, Inc. (HELCO) and Maui Electric Company, Limited (MECO) reached agreements with the Consumer Advocate and filed requests to continue their four existing DSM programs. In November 2001, the PUC issued orders (one of which was later amended) that, subject to certain reporting requirements and other conditions, approved (1) the agreements regarding the temporary continuation of HECO's five existing DSM programs until HECO's next rate case and (2) the agreements regarding the temporary continuation of HELCO's and MECO's DSM programs until one year after the PUC makes a revenue requirements determination in HECO's next rate case. Under the orders, however, HELCO and MECO are allowed to recover only lost margins and shareholder incentives accrued through the date that interim rates are established in HECO's next rate case, but may request to extend the time of such accrual and recovery for up to one additional year. In 2002, MECO's revenues from shareholder incentives were $0.7 million lower than the amount that would have been recorded if MECO had not agreed to cap such incentives when its authorized return on rate base was exceeded. Also in 2002, HELCO slightly exceeded its authorized return on rate base resulting in a reduction to shareholders incentives of approximately $31,000, which HELCO recorded in January 2003. In 2002, HECO did not exceed its authorized return on rate base.

With respect to HECO's agreement with the Consumer Advocate regarding HECO's three commercial and industrial DSM programs, the parties agreed on August 7, 2003, subject to PUC approval, to a delay in the filing of HECO's next rate case by approximately 12 months, with the result that the rate case would be filed using a 2005 test year. A similar agreement with respect to its two residential DSM programs was reached on August 12, 2003, subject to PUC approval. The other components of the existing agreements, as approved by the PUC, would be continued under the new agreements. On August 26, 2003, the PUC issued orders approving the new agreements.

requested that the effective date of the proposed changes coincide with the effective date of the rates established in HECO's next rate case proceeding so that HECO's financial results would not be negatively impacted by the depreciation rates and method ultimately approved by the PUC. In July 2003, the Consumer Advocate submitted its direct testimony and recommended depreciation expense approximately $31.8 million, or 45%, less than HECO's requested $70.8 million in annual depreciation expense. HECO's rebuttal testimony was submitted in August 2003.

Most recent rate requests

HEI's electric utility subsidiaries initiate PUC proceedings from time to time to request electric rate increases to cover rising operating costs (e.g., the cost of purchased power) and the cost of plant and equipment, including the cost of new capital projects to maintain and improve service reliability. As of November 1, 2003, the return on average common equity (ROACE) found by the PUC to be reasonable in the most recent final rate decision for each utility was 11.40% for HECO (D&O issued on December 11, 1995, based on a 1995 test year), 11.50% for HELCO (D&O issued on February 8, 2001, based on a 2000 test year) and 10.94% for MECO (amended D&O issued on April 6, 1999, based on a 1999 test year). For 2002, the actual ROACEs (calculated under the rate-making method and reported semiannually to the PUC) for HECO, HELCO and MECO were 11.33%, 7.52% and 10.30%, respectively. For the twelve months ended June 30, 2003, the actual ROACEs for HECO, HELCO and MECO were 9.79%, 7.02% and 10.42%, respectively.

As of November 1, 2003, the return on average rate base (ROR) found by the PUC to be reasonable in the most recent final rate decision for each utility was 9.16% for HECO, 9.14% for HELCO and 8.83% for MECO (D&Os noted above). For 2002, the actual RORs (calculated under the rate-making method and reported semiannually to the PUC) for HECO, HELCO and MECO were 8.94%, 9.15% and 8.83%, respectively. MECO's and HELCO's RORs were higher than 8.83% and 9.14%, respectively, for 2002. Consequently, an adjustment was made to their shareholder incentives under their demand-side management (DSM) programs in accordance with their agreements for the temporary continuation of the programs. See "Other regulatory matters, Demand-side management programs – agreements with the Consumer Advocate." For the twelve months ended June 30, 2003, the actual RORs for HECO, HELCO and MECO were 8.19%, 9.09% and 8.94%, respectively.

Hawaiian Electric Company, Inc. HECO has not initiated a rate case for several years, but in 2001 it committed to initiate a rate case within three years, using a 2003 or 2004 test year, as part of the agreements described below. HECO has requested that the time for initiating the rate case be extended by 12 months, and the PUC has approved the request, with the result that the rate case is to be initiated approximately 12 months later, using a 2005 test year. See "Other regulatory matters, Demand-side management programs – agreements with the Consumer Advocate."

Hawaii Electric Light Company, Inc. In early 2001, HELCO received a final D&O from the PUC authorizing an $8.4 million, or 4.9% increase in annual revenues, effective February 15, 2001 and based on an 11.50% ROACE. The D&O included in rate base $7.6 million for pre-air permit facilities needed for the delayed Keahole power plant expansion project that the PUC had also found to be used or useful to support the existing generating units at Keahole.

On June 1, 2001, the PUC issued an order approving a new standby service rate schedule rider for HELCO. The standby service rider issue had been bifurcated from the rest of the rate case. The rider provides the rates, terms and conditions for obtaining backup and supplemental electric power from the utility when a customer obtains all or part of its electric power from sources other than HELCO.

The timing of a future HELCO rate increase request to recover costs relating to the delayed Keahole power plant expansion project, i.e., adding two combustion turbines (CT-4 and CT-5) at Keahole, including the remaining cost of pre-air permit facilities, will depend on future circumstances. See "HELCO power situation" in note (4) of HECO's "Notes to Consolidated Financial Statements."

Other regulatory matters 9/30/03 Item 10-Q

Demand-side management programs - lost margins and shareholder incentives. HECO, HELCO and MECO's energy efficiency DSM programs, currently approved by the PUC, provide for the recovery of lost margins and the earning of shareholder incentives.

Lost margins are accrued and collected prospectively based on the programs' forecast levels of participation, and are subject to two adjustments based on (1) the actual level of participation and (2) the results of impact evaluation reports. The difference between the adjusted lost margins and the previously collected lost margins are subject to refund or recovery, with any over or under collection accruing interest at HECO, HELCO, or MECO's authorized rate of return on rate base. HECO, HELCO and MECO plan to file the impact evaluation report for the 2000-2002 period with the PUC in the fourth quarter of 2004 and adjust the lost margin recovery as required. Past adjustments required for lost margins have not had a material effect on HECO, HELCO or MECO's financial statements.

Shareholder incentives are accrued currently and collected retrospectively based on the programs' actual levels of participation for the prior year. Beginning in 2001, shareholder incentives collected became subject to retroactive adjustment based on the results of impact evaluation reports, similar to the adjustment process for lost margins.

Demand-side management programs – agreements with the Consumer Advocate. In October 2001, HECO and the Consumer Advocate finalized agreements, subject to PUC approval, under which HECO's three commercial and industrial DSM programs and two residential DSM programs would be continued until HECO's next rate case, which, under the agreements, HECO committed to file using a 2003 or 2004 test year and following the PUC's rules for determining the test year. The PUC rules require that an application be filed between July and December 2003 in order to use a 2004 test year. The agreements for the temporary continuation of HECO's existing DSM programs were in lieu of HECO continuing to seek approval of new 5-year DSM programs. Any DSM programs to be in place after HECO's next rate case will be determined as part of the case. Under the agreements, HECO will cap the recovery of lost margins and shareholder incentives if such recovery would cause HECO to exceed its current "authorized return on rate base" (i.e. the rate of return found by the PUC to be reasonable in the most recent rate [illegible]

Other regulatory matters 12/31/03 Form 10-K/A

Demand-side management programs - lost margins and shareholder incentives. HECO, HELCO and MECO's energy efficiency DSM programs, currently approved by the PUC, provide for the recovery of lost margins and the earning of shareholder incentives.

Lost margins are accrued and collected prospectively based on the programs' forecast levels of participation, and are subject to two adjustments based on (1) the actual level of participation and (2) the results of impact evaluation reports. The difference between the adjusted lost margins and the previously collected lost margins are subject to refund or recovery, with any over- or under-collection accruing interest at HECO, HELCO, or MECO's authorized rate of return on rate base. HECO, HELCO and MECO plan to file the impact evaluation report for the 2000-2002 period with the PUC in the fourth quarter of 2004 and adjust the lost margin recovery as required. Past adjustments required for lost margins have not had a material effect on HECO, HELCO or MECO's financial statements.

Shareholder incentives are accrued currently and collected retrospectively based on the programs' actual levels of participation for the prior year. Beginning in 2001, shareholder incentives collected are subject to retroactive adjustment based on the results of impact evaluation reports, similar to the adjustment process for lost margins.

Demand-side management programs – agreements with the Consumer Advocate. In October 2001, HECO and the Consumer Advocate finalized agreements, subject to PUC approval, for the continuation of HECO's three commercial and industrial DSM programs and two residential DSM programs until HECO's next rate case, which HECO committed to file using a 2003 or 2004 test year. These agreements were in lieu of HECO continuing to seek approval of new 5-year DSM programs. Any DSM programs to be in place after HECO's next rate case will be determined as part of the case. Under the agreements, HECO will cap the recovery of lost margins and shareholder incentives if such recovery would cause HECO to exceed its current "authorized return on rate base" (i.e. the rate of return on rate base found by the PUC to be reasonable in the most recent rate case for HECO). HECO also agreed it will not pursue the continuation of lost margins recovery and shareholder incentives through a surcharge mechanism in future rate cases. In October 2001, HELCO and MECO reached similar agreements with the Consumer Advocate and filed requests to continue their four existing DSM programs. In November 2001, the PUC issued orders (one of which was later amended) that, subject to certain reporting requirements and other conditions, approved (1) the agreements regarding the temporary continuation of HECO's five existing DSM programs until HECO's next rate case and (2) the agreements regarding the temporary continuation of HELCO's and MECO's DSM programs until one year after the PUC makes a revenue requirements determination in HECO's next rate case. Under the orders, however, HELCO and MECO are allowed to recover only lost margins and shareholder incentives accrued through the date that interim rates are established in HECO's next rate case, but may request to extend the time of such accrual and recovery for up to one additional year. In 2002, MECO's revenues from shareholder incentives were $0.7 million lower than the amount that would have been recorded if MECO had not agreed to cap such incentives when its authorized ROR was exceeded. Also in 2002, HELCO slightly exceeded its authorized ROR resulting in a reduction of revenues from shareholders incentives for 2002 by $31,000 (recorded in January 2003). In 2002, HECO did not exceed its authorized ROR. In 2003, none of the electric utilities exceeded their respective authorized RORs.

As part of HECO's agreement with the Consumer Advocate regarding HECO's commercial, industrial and residential DSM programs, the parties agreed in August 2003, and the PUC approved, that HECO could delay the filing of its next rate case by approximately 12 months, with the result that the rate case will be filed in the second half of 2004 using a 2005 test year. The other components of the existing agreements, as approved by the PUC, would be continued under the new agreements.

Collective bargaining agreements

HECO, HELCO and MECO reached a new collective bargaining agreement in 2003 with the union which represents approximately 60% of its employees. See "Collective bargaining agreements" in Note 11 in HECO's "Notes to Consolidated Financial Statements."

Other regulatory matters 2/26/04 Form 8-K

Demand-side management programs - lost margins and shareholder incentives. HECO, HELCO and MECO's energy efficiency DSM programs, currently approved by the PUC, provide for the recovery of lost margins and the earning of shareholder incentives.

Lost margins are accrued and collected prospectively based on the programs' forecast levels of participation, and are subject to two adjustments based on (1) the actual level of participation and (2) the results of impact evaluation reports. The difference between the adjusted lost margins and the previously collected lost margins are subject to refund or recovery, with any over- or under-collection accruing interest at HECO, HELCO, or MECO's authorized rate of return on rate base. HECO, HELCO and MECO plan to file the impact evaluation report for the 2000-2002 period with the PUC in the fourth quarter of 2004 and adjust the lost margin recovery as required. Past adjustments required for lost margins have not had a material effect on HECO, HELCO or MECO's financial statements.

Shareholder incentives are accrued currently and collected retrospectively based on the programs' actual levels of participation for the prior year. Beginning in 2001, shareholder incentives collected are subject to retroactive adjustment based on the results of impact evaluation reports, similar to the adjustment process for lost margins.

Demand-side management programs – agreements with the Consumer Advocate. In October 2001, HECO and the Consumer Advocate finalized agreements, subject to PUC approval, for the continuation of HECO's three commercial and industrial DSM programs and two residential DSM programs until HECO's next rate case, which HECO committed to file using a 2003 or 2004 test year. These agreements were in lieu of HECO continuing to seek approval of new 5-year DSM programs. Any DSM programs to be in place after HECO's next rate case will be determined as part of the case. Under the agreements, HECO will cap the recovery of lost margins and shareholder incentives if such recovery would cause HECO to exceed its current "authorized return on rate base" (i.e. the rate of return on rate base found by the PUC to be reasonable in the most recent rate case for HECO). HECO also agreed : will not pursue the continuation of lost margins recovery and shareholder incentives through a surcharge mechanism in future rate cases. In October 2001, HELCO and MECO reached similar agreements with the Consumer Advocate and filed requests to continue their four existing DSM programs. In November 2001, the PUC issued orders (one of which was later amended) that, subject to certain reporting requirements and other conditions, approved (1) the agreements regarding the temporary continuation of HECO's five existing DSM programs until HECO's next rate case and (2) the agreements regarding the temporary continuation of HELCO's and MECO's DSM programs until one year after the PUC makes a revenue requirements determination in HECO's next rate case. Under the orders, however, HELCO and MECO are allowed to recover only lost margins and shareholder incentives accrued through the date that interim rates are established in HECO's next rate case, but may request to extend the time of such accrual and recovery for up to one additional year. In 2002, MECO's revenues from shareholder incentives were $0.7 million lower than the amount that would have been recorded if MECO had not agreed to cap such incentives when its authorized ROR was exceeded. Also in 2002, HELCO slightly exceeded its authorized ROR resulting in a reduction of revenues from shareholders incentives for 2002 by $31,000 (recorded in January 2003). In 2002, HECO did not exceed its authorized ROR. In 2003, none of the electric utilities exceeded their respective authorized RORs.

As part of HECO's agreement with the Consumer Advocate regarding HECO's commercial, industrial and residential DSM programs, the parties agreed in August 2003, and the PUC approved, that HECO could delay the filing of its next rate case by approximately 12 months, with the result that the rate case will be filed in the second half of 2004 using a 2005 test year. The other components of the existing agreements, as approved by the PUC, would be continued under the new agreements.

Other regulatory matters 3/31/04 Rev 10-6

Demand-side management programs - lost margins and shareholder incentives. HECO, HELCO and MECO's energy efficiency DSM programs, currently approved by the PUC, provide for the recovery of lost margins and the earning of shareholder incentives.

Lost margins are accrued and collected prospectively based on the programs' forecast levels of participation, and are subject to two adjustments based on (1) the actual level of participation and (2) the results of impact evaluation reports. The difference between the adjusted lost margins and the previously collected lost margins are subject to refund or recovery, with any over- or under-collection accruing interest at HECO, HELCO, or MECO's authorized rate of return on rate base. HECO, HELCO and MECO plan to file the impact evaluation report for the 2000-2002 period with the PUC in the fourth quarter of 2004 and adjust the lost margin recovery as required. Past adjustments required for lost margins have not had a material effect on HECO, HELCO or MECO's financial statements.

Shareholder incentives are accrued currently and collected retrospectively based on the programs' actual levels of participation for the prior year. Beginning in 2001, shareholder incentives collected are subject to retroactive adjustment based on the results of impact evaluation reports, similar to the adjustment process for lost margins.

Demand-side management programs – agreements with the Consumer Advocate. In October 2001, HECO and the Consumer Advocate finalized agreements, subject to PUC approval, for the continuation of HECO's three commercial and industrial DSM programs and two residential DSM programs until HECO's next rate case, which HECO committed to file using a 2003 or 2004 test year. These agreements were in lieu of HECO continuing to seek approval of new 5-year DSM programs. Any DSM programs to be in place after HECO's next rate case will be determined as part of the case. Under the agreements, HECO will cap the recovery of lost margins and shareholder incentives if such recovery would cause HECO to exceed its current "authorized return on rate base" (i.e. the rate of return on rate base found by the PUC to be reasonable in the most recent rate case for HECO). HECO also agreed it will not pursue the continuation of lost margins recovery and shareholder incentives through a surcharge mechanism in future rate cases. In October 2001, HELCO and MECO reached similar agreements with the Consumer Advocate and filed requests to continue their four existing DSM programs. In November 2001, the PUC issued orders (one of which was later amended) that, subject to certain reporting requirements and other conditions, approved (1) the agreements regarding the temporary continuation of HECO's five existing DSM programs until HECO's next rate case and (2) the agreements regarding the temporary continuation of HELCO's and MECO's DSM programs until one year after the PUC makes a revenue requirements determination in HECO's next rate case. Under the orders, however, HELCO and MECO are allowed to recover only lost margins and shareholder incentives accrued through the date that interim rates are established in HECO's next rate case, but may request to extend the time of such accrual and recovery for up to one additional year.

As part of HECO's agreement with the Consumer Advocate regarding HECO's commercial, industrial and residential DSM programs, the parties agreed in August 2003, and the PUC approved, that HECO could delay the filing of its next rate case by approximately 12 months, with the result that the rate case will be filed in the second half of 2004 using a 2005 test year. The other components of the existing agreements, as approved by the PUC, would be continued under the new agreements.

Collective bargaining agreements

See "Collective bargaining agreements" in note (5) in HECO's "Notes to consolidated financial statements."

Legislation

Congress and the Hawaii legislature periodically consider legislation that could have positive or negative effects on the utilities and their customers. For example, although it is currently stalled in a House-Senate conference committee, comprehensive energy legislation is still before Congress that could increase the domestic supply of oil as well as increase support for energy conservation programs and mandate the use of renewables by utilities.

In its 2001 session, the Hawaii legislature passed a law establishing "renewable portfolio standard" goals for electric utilities of 7% by December 31, 2003, 8% by December 31, 2005 and 9% by December 31, 2010. HECO, HELCO and MECO are permitted to aggregate their renewable portfolios in order to achieve these goals. Any electric utility whose percentage of sales of electricity represented by renewable energy does not meet these goals will have

Nevertheless, HELCO's ROACE may be negatively impacted as electric rates will not change for the additions of CT-4 and CT-5 until HELCO files a rate increase application and the PUC grants HELCO rate relief. For the twelve months ended June 30, 2004, the weighted average ROACEs (rate-making method) for HECO, HELCO and MECO were 9.94%, 6.13% and 10.34%, respectively.

The return on average rate base (ROR) found by the PUC to be reasonable in the most recent final rate decision for each utility was 9.16% for HECO, 9.14% for HELCO and 8.83% for MECO (D&Os noted above). For 2003, the actual RORs (semiannually calculated under the rate-making method and reported to the PUC) for HECO, HELCO and MECO were 7.95%, 8.65% and 8.79%, respectively. For the twelve months ended June 30, 2004, the weighted average RORs (rate-making method) for HECO, HELCO and MECO were 8.35%, 8.03% and 9.18%, respectively.

Hawaiian Electric Company, Inc. HECO has not initiated a rate case since 1993, but in 2001 it committed to initiate a rate case within three years, using a 2003 or 2004 test year. The PUC later approved HECO's request that the time for initiating the rate case be extended by 12 months, with the result that the rate case is to be initiated in the second half of 2004, using a 2005 test year. In May 2004, HECO's Notice of Intent to file a general rate increase application was filed with the PUC. See the discussion below under "Other regulatory matters, Demand-side management programs – agreements with the Consumer Advocate."

In October 2002, HECO filed an application with the PUC for approval to change its depreciation rates based on a study of depreciation expense for 2000 and to change to vintage amortization accounting for selected plant accounts. In its application, HECO requested that the effective date of the proposed changes coincide with the effective date of the rates established in HECO's next rate case proceeding so that HECO's financial results would not be negatively impacted by the depreciation rates and method ultimately approved by the PUC. In July 2003, the Consumer Advocate submitted its direct testimony and recommended depreciation expense approximately $31.8 million, or 45%, less than HECO's requested $70.8 million in annual 2000 depreciation expense. In March 2004, HECO and the Consumer Advocate reached an agreement, subject to PUC approval, under which HECO would change its depreciation rates and change to vintage amortization accounting for selected plant accounts, effective with the PUC's final decision and order on HECO's application. If approved by the PUC, the new rates and method of accounting under the settlement agreement would change depreciation expense in periods following the effective date from amounts that would have been accrued if the current depreciation rates and method of accounting remained in effect. For example, if the settlement agreement had been in effect in 2000, it would have resulted in an estimated $65.0 million in annual depreciation expense based on the study of depreciation expense for 2000, compared to recorded depreciation expense of $66.5 million.

Hawaii Electric Light Company, Inc. The timing of a future HELCO rate increase request to recover costs relating to the delayed installation of two combustion turbines (CT-4 and CT-5) at Keahole will depend on future circumstances. See "HELCO power situation" in note (5) of HECO's "Notes to Consolidated Financial Statements."

Other regulatory matters 6/30/04 Form 10-Q

Demand-side management programs - lost margins and shareholder incentives. HECO, HELCO and MECO's energy efficiency DSM programs, currently approved by the PUC, provide for the recovery of lost margins and the earning of shareholder incentives.

Lost margins are accrued and collected prospectively based on the programs' forecast levels of participation, and are subject to two adjustments based on (1) the actual level of participation and (2) the results of impact evaluation reports. The difference between the adjusted lost margins and the previously collected lost margins are subject to refund or recovery, with any over- or under-collection accruing interest at HECO, HELCO or MECO's authorized rate of return on rate base. HECO, HELCO and MECO plan to file the impact evaluation report for the 2000-2002 period with the PUC in the fourth quarter of 2004 and adjust the lost margin recovery as required. Past adjustments required for lost margins have not had a material effect on HECO, HELCO or MECO's financial statements.

Shareholder incentives are accrued currently and collected retrospectively based on the programs' actual levels of participation for the prior year. Beginning in 2001, shareholder incentives collected are subject to retroactive adjustment based on the results of impact evaluation reports, similar to the adjustment process for lost margins.

<u>Demand-side management programs – agreements with the Consumer Advocate.</u> In October 2001, HECO and the Consumer Advocate finalized agreements, subject to PUC approval, for the continuation of HECO's three commercial and industrial DSM programs and two residential DSM programs until HECO's next rate case, which HECO committed to file using a 2003 or 2004 test year. These agreements were in lieu of HECO continuing to seek approval of new 5-year DSM programs. Any DSM programs to be in place after HECO's next rate case will be determined as part of the case. Under the agreements, HECO will cap the recovery of lost margins and shareholder incentives if such recovery would cause HECO to exceed its current "authorized return on rate base" (i.e. the rate of return on rate base found by the PUC to be reasonable in the most recent rate case for HECO). HECO also agreed it will not pursue the continuation of lost margins recovery and shareholder incentives through a surcharge mechanism in future rate cases. In October 2001, HELCO and MECO reached similar agreements with the Consumer Advocate and filed requests to continue their four existing DSM programs. In November 2001, the PUC issued orders (one of which was later amended) that, subject to certain reporting requirements and other conditions, approved (1) the agreements regarding the temporary continuation of HECO's five existing DSM programs until HECO's next rate case and (2) the agreements regarding the temporary continuation of HELCO's and MECO's DSM programs until one year after the PUC makes a revenue requirements determination in HECO's next rate case. Under the orders, however, HELCO and MECO are allowed to recover only lost margins and shareholder incentives accrued through the date that interim rates are established in HECO's next rate case, but may request to extend the time of such accrual and recovery for up to one additional year.

One of the conditions to the temporary continuation of the DSM programs requires the utilities and the Consumer Advocate review, every six months, the economic and rate impacts resulting from implementing the agreement. In reviewing HELCO's ROR for 2003, the Consumer Advocate raised an issue as to whether the Keahole settlement expenses accrued in November 2003 should be included in the rate-making calculation for HELCO's ROR for the purpose of determining whether HELCO's ROR exceeded its current "authorized" ROR due to its recovery of lost margins and shareholder incentives. Excluding the $3.1 million amount accrued in November 2003, HELCO's ROR for 2003 would have exceeded HELCO's current authorized ROR by an amount greater than HELCO's lost margins and shareholder incentives for the year. In order to resolve any issue of whether HELCO's recovery of lost margins and shareholder incentives allowed HELCO to exceed its current authorized ROR, HELCO agreed to refund, with interest, all of the lost margins and shareholder incentives earned in 2003. In June 2004, HELCO recorded reduced revenues of $1.1 million to reflect the lost margins and shareholder incentives for 2003 that will be refunded to customers. No issues have been raised regarding the lost margins and shareholder incentives earned by HECO or MECO in 2003.

As part of HECO's agreement with the Consumer Advocate regarding HECO's commercial, industrial and residential DSM programs, the parties agreed in August 2003, and the PUC approved, that HECO could delay the filing of its next rate case by approximately 12 months, with the result that the rate case will be filed in the second half will not change for the additions of CT-4 and CT-5 until HELCO files a rate increase application and the PUC grants HELCO rate relief. For the twelve months ended June 30, 2004, the weighted average ROACEs (rate-making method) for HECO, HELCO and MECO were 9.94%, 6.13% and 10.34%, respectively.

The return on average rate base (ROR) found by the PUC to be reasonable in the most recent final rate decision for each utility was 9.16% for HECO, 9.14% for HELCO and 8.83% for MECO (D&Os noted above). For 2003, the actual RORs (semiannually calculated under the rate-making method and reported to the PUC) for HECO, HELCO and MECO were 7.95%, 8.65% and 8.79%, respectively. For the twelve months ended June 30, 2004, the weighted average RORs (rate-making method) for HECO, HELCO and MECO were 8.35%, 8.03% and 9.18%, respectively.

If required to record significant charges to AOCI, as described previously under "Pension and other postretirement benefits," the electric utilities' RORs could increase and exceed the PUC authorized RORs, which may ultimately result in reduced revenues and lower earnings.

Hawaiian Electric Company, Inc. HECO has not initiated a rate case since 1993, but in 2001 it committed to initiate a rate case within three years, using a 2003 or 2004 test year. The PUC later approved HECO's request that the time for initiating the rate case be extended by 12 months, with the result that the rate case is to be initiated in the second half of 2004, using a 2005 test year. See the discussion below under "Other regulatory matters, Demand-side management programs – agreements with the Consumer Advocate." In May 2004, HECO filed with the PUC a Notice of Intent to file a general rate increase application. HECO expects to file its rate case in November 2004.

In October 2002, HECO filed an application with the PUC for approval to change its depreciation rates based on a study of depreciation expense for 2000 and to change to vintage amortization accounting for selected plant accounts. In July 2003, the Consumer Advocate submitted its direct testimony and recommended depreciation expense approximately $31.8 million, or 45%, less than HECO's requested $70.8 million in annual 2000 depreciation expense. In March 2004, HECO and the Consumer Advocate reached an agreement, subject to PUC approval, under which HECO would make the changes effective with the PUC's final D&O on HECO's application. In September 2004, the PUC approved the agreement, and HECO changed its depreciation rates and changed to vintage amortization accounting for selected plant accounts. If the new rates and accounting had been in effect from the beginning of 2004, depreciation expense for the first eight months of 2004 would have been an estimated $1.3 million lower.

Hawaii Electric Light Company, Inc. The timing of a future HELCO rate increase request to recover costs relating to the delayed installation of two combustion turbines (CT-4 and CT-5) at Keahole will depend on future circumstances. See "HELCO power situation" in note 5 of HECO's "Notes to Consolidated Financial Statements."

Other regulatory matters 9/30/04 Form 10-Q

Demand-side management programs - lost margins and shareholder incentives. HECO, HELCO and MECO's energy efficiency DSM programs, currently approved by the PUC, provide for the recovery of lost margins and the earning of shareholder incentives.

Lost margins are accrued and collected prospectively based on the programs' forecast levels of participation, and are subject to two adjustments based on (1) the actual level of participation and (2) the results of impact evaluation reports. The difference between the adjusted lost margins and the previously collected lost margins are subject to refund or recovery, with any over- or under-collection accruing interest at HECO, HELCO or MECO's authorized rate of return on rate base. HECO, HELCO and MECO plan to file the impact evaluation report for the 2000-2002 period with the PUC in the fourth quarter of 2004 and adjust the lost margin recovery as required. Past adjustments required for lost margins have not had a material effect on HECO, HELCO or MECO's financial statements.

Shareholder incentives are accrued currently and collected retrospectively based on the programs' actual levels of participation for the prior year. Beginning in 2001, shareholder incentives collected are subject to retroactive adjustment based on the results of impact evaluation reports, similar to the adjustment process for lost margins.

Demand-side management programs – agreements with the Consumer Advocate. In October 2001, HECO and the Consumer Advocate finalized agreements, subject to PUC approval, for the continuation of HECO's three commercial and industrial DSM programs and two residential DSM programs until HECO's next rate case, which HECO committed to file using a 2003 or 2004 test year. These agreements were in lieu of HECO continuing to seek approval of new 5-year DSM programs. Any DSM programs to be in place after HECO's next rate case will be determined as part of the case. Under the agreements, HECO will cap the recovery of lost margins and shareholder incentives if such recovery would cause HECO to exceed its current "authorized return on rate base" (i.e. the rate of return on rate base found by the PUC to be reasonable in the most recent rate case for HECO). HECO also agreed it will not pursue the continuation of lost margins recovery and shareholder incentives through a surcharge mechanism in future rate cases. In October 2001, HELCO and MECO reached similar agreements with the Consumer Advocate and filed requests to continue their four existing DSM programs. In November 2001, the PUC issued orders (one of which was later amended) that, subject to certain reporting requirements and other conditions, approved (1) the agreements regarding the temporary continuation of HECO's five existing DSM programs until HECO's next rate case and (2) the agreements regarding the temporary continuation of HELCO's and MECO's DSM programs until one year after the PUC makes a revenue requirements determination in HECO's next rate case. Under the orders, however, HELCO and MECO are allowed to recover only lost margins and shareholder incentives accrued through the date that interim rates are established in HECO's next rate case, but may request to extend the time of such accrual and recovery for up to one additional year.

One of the conditions to the temporary continuation of the DSM programs requires the utilities and the Consumer Advocate to review, every six months, the economic and rate impacts resulting from implementing the agreement. In reviewing HELCO's ROR for 2003, the Consumer Advocate raised an issue as to whether the Keahole settlement expenses accrued in November 2003 should be included in the rate-making calculation for HELCO's ROR for the purpose of determining whether HELCO's ROR exceeded its current "authorized" ROR due to its recovery of lost margins and shareholder incentives. Excluding the $3.1 million amount accrued in November 2003, HELCO's ROR for 2003 would have exceeded HELCO's current authorized ROR by an amount greater than HELCO's lost margins and shareholder incentives for the year. In order to resolve any issue of whether HELCO's recovery of lost margins and shareholder incentives allowed HELCO to exceed its current authorized ROR, HELCO agreed to refund, with interest, all of the lost margins and shareholder incentives earned in 2003. In June 2004, HELCO recorded reduced revenues of $1.1 million to reflect the lost margins and shareholder incentives for 2003 that were refunded to customers in August 2004. No issues have been raised regarding the lost margins and shareholder incentives earned by HECO or MECO in 2003.

As part of HECO's agreement with the Consumer Advocate regarding HECO's commercial, industrial and residential DSM programs, the parties agreed in August 2003, and the PUC approved, that HECO could delay the filing of its next rate case by approximately 12 months, with the result that the rate case is currently expected to be filed in November 2004 using a 2005 test year. The other components of the existing agreements, as approved by the PUC, would be continued under the new agreements.

In mid-2004, HECO and the Consumer Advocate reached agreement on a residential load management program and a commercial and industrial load management program and filed the agreements with the PUC requesting expedited approval. In October 2004, the PUC approved HECO's residential and commercial and industrial load management programs, and the implementation of these programs is expected to begin in early 2005. The residential load management program includes a monthly electric bill credit for eligible customers who participate in the program, which allows HECO to disconnect the customer's residential electric water heaters from HECO's system to reduce system load when deemed necessary by HECO. The commercial and industrial load management program provides an incentive on the portion of the demand load that eligible customers allow to be controlled or interrupted by HECO. In addition, if HECO interrupts the load, an incentive is paid on the kilowatthours interrupted.

Avoided cost generic docket. In May 1992, the PUC instituted a generic investigation including all of Hawaii's electric utilities to examine the proxy method and the proxy method formula used by the electric utilities to calculate their avoided energy costs and Schedule Q rates. In addition to the electric utilities, the parties to the 1992 docket include ... the Department of Defense, and representatives of existing or potential independent power the stipulation and file such information within 60 days of the date of the order, and stated that further action will follow. In September 2004, the PUC approved a request for an extension of time until the end of March 2005 for all parties to submit the requested information.

Collective bargaining agreements

See "Collective bargaining agreements" in note 5 in HECO's "Notes to Consolidated Financial Statements."

Legislation

Congress and the Hawaii legislature periodically consider legislation that could have positive or negative effects on the utilities and their customers. For example, although it is currently stalled in a House-Senate conference committee, comprehensive energy legislation is still before Congress that could increase the domestic supply of oil as well as increase support for energy conservation programs and mandate the use of renewables by utilities.

The 2001 Hawaii Legislature adopted a law which required the utilities to meet a renewable portfolio standard of 7% by December 31, 2003. The Company met this standard because over 8% of the utilities' consolidated electricity sales for 2003 were from renewable resources (as defined under the renewable portfolio standards law). However, the 2004 Hawaii Legislature amended the renewable portfolio standards law to require electric utilities to meet a renewable portfolio standard of 8% by December 31, 2005, 10% by December 31, 2010, 15% by December 31, 2015 and 20% by December 31, 2020, but the amended law contains no penalties if the standards are not met. HECO, HELCO and MECO are permitted to aggregate their renewable portfolios in order to achieve these standards. The PUC has to determine if an electric utility is not able to meet the standard in a cost-effective manner or due to circumstances beyond its control. If such a determination is made, the utility is relieved of its responsibility to achieve the standard for that period of time. The law also requires participation by the State to support and facilitate achievement of the renewable portfolio standards and directs the PUC to develop and implement a rate structure to encourage the use of renewable energy. An independent, peer-reviewed study will be conducted by the Hawaii Natural Energy Institute. The study will look at the electric utilities' capability of achieving the standards based on a number of factors including impact on consumer rates, utility system reliability and stability, costs and availability of appropriate renewable energy resources and technologies, permitting approvals, and impacts on the economy, culture, community and environment. While the Company met the 7% target for 2003, it believes it may be difficult to meet the standard in future years, particularly if sales of electricity increase as projected. Thus, at this time, management cannot predict the impact of this law or of other proposed congressional and Hawaii legislation on the Company or its customers.

The Company currently supports renewable sources in various ways, including their solar water heating and heat pump programs and their purchased power contracts with nonutility generators using renewable sources (e.g., refuse-fired, geothermal, hydroelectric and wind turbine generating systems). On December 30, 2003, HELCO signed an approximately 10 MW as-available wind power contract with Hawi Renewable Development, and the contract was approved by the PUC on May 14, 2004. Further, a contract with Apollo Energy Corporation to repower an existing 7 MW windfarm to 20 MW was signed on October 13, 2004, and an application for PUC approval will be submitted soon.

The electric utilities continue to initiate and support many renewable energy research and development projects to help develop these technologies (e.g., photovoltaic projects). They are also conducting integrated resource planning to evaluate the use of more renewables and, in December 2002, HECO formed an unregulated subsidiary, Renewable Hawaii, Inc. (RHI), with initial approval to invest up to $10 million in renewable energy projects. Beginning in 2003, RHI solicited competitive proposals for investment opportunities in projects (1 MW or larger) to supply renewable energy on the islands of Oahu, Maui, Molokai, Lanai and Hawaii. RHI is seeking to take a passive, minority interest in such projects to help stimulate the addition of cost-effective, commercially viable renewable energy generation in the state of Hawaii. RHI has signed a memorandum of understanding (MOU) and project agreement for a small-scale municipal solid waste project and a MOU for a small-scale landfill gas project. Investments by RHI will be made only after the developers secure the necessary approvals and permits and an approved PPA with HECO, HELCO or MECO.

Hawaii has a net energy metering law, which requires that electric utilities offer net energy metering to eligible customer generators (i.e. a customer generator may be a net user or supplier of energy and will make payment to or

Hawaiian Electric Company, Inc. The final D&O for the last rate case on Oahu was issued in 1995.

In November 2004, HECO filed a request with the PUC to increase base rates 9.9%, or $98.6 million in annual base revenues, based on a 2005 test year, a 9.11% return on rate base and an 11.5% return on average common equity. The requested increase includes transferring the cost of existing energy conservation and efficiency programs from a surcharge line item on electric bills into base electricity charges. Excluding this surcharge transfer amount, the requested net increase to customers is 7.3%, or $74.2 million. Approximately $20.4 million of the $74.2 million net request is for the costs of new residential and commercial energy conservation and efficiency programs. The balance of the request is largely for recovery of (1) the costs of capital improvement projects completed since the last rate case, (2) the proposed purchase of up to an additional 29 MW of firm capacity and energy from Kalaeloa Partners, L.P., which is subject to PUC review and approval, (3) other measures taken to address peak load increases arising out of economic growth and increasing electricity use, and (4) increased operation and maintenance expenses. The PUC held a public hearing in January 2005 and evidentiary hearings are expected in the third quarter of 2005. An interim decision is expected in the fourth quarter of 2005.

In October 2002, HECO filed an application with the PUC for approval to change its depreciation rates based on a study of depreciation expense for 2000 and to change to vintage amortization accounting for selected plant accounts. In March 2004, HECO and the Consumer Advocate reached an agreement and the PUC approved the agreement in September 2004. In accordance with the agreement, HECO changed its depreciation rates and changed to vintage amortization accounting for selected plant accounts effective September 1, 2004. Under vintage amortization accounting, additions to electric utility plant in each year are grouped together in a vintage account for that year, as opposed to tracking each asset separately. Each vintage account is amortized over its average service life as determined in the depreciation study and, when fully amortized, the original cost of that vintage account is retired from utility plant in service. If the new rates and accounting had been in effect from the beginning of 2004, depreciation expense for the first eight months of 2004 would have been an estimated $1.3 million lower.

Hawaii Electric Light Company, Inc. The timing of a future HELCO rate increase request to recover costs, including cost for the installation of two combustion turbines (CT-4 and CT-5) at Keahole, will depend on future circumstances. See "HELCO power situation" in Note 3 of the "Notes to Consolidated Financial Statements."

Other regulatory matters $\boxed{\text{12/31/04 Form 10-K}}$

Demand-side management programs - lost margins and shareholder incentives. HECO, HELCO and MECO's energy efficiency DSM programs, currently approved by the PUC, provide for the recovery of lost margins and the earning of shareholder incentives.

Lost margins are accrued and collected prospectively based on the programs' forecast levels of participation, and are subject to two adjustments based on (1) the actual level of participation and (2) the results of impact evaluation reports. The difference between the adjusted lost margins and the previously collected lost margins are subject to refund or recovery, with any over- or under-collection accruing interest at HECO, HELCO or MECO's authorized rate of return on rate base. HECO, HELCO and MECO filed the impact evaluation report for the 2000-2003 period with the PUC in November 2004 and plan to adjust the lost margin recovery as required in the second quarter of 2005. Past adjustments required for lost margins have not had a material effect on HECO, HELCO or MECO's financial statements.

Shareholder incentives are accrued currently and collected retrospectively based on the programs' actual levels of participation for the prior year. Beginning in 2001, shareholder incentives collected are subject to retroactive adjustment based on the results of impact evaluation reports, similar to the adjustment process for lost margins.

Demand-side management programs – agreements with the Consumer Advocate. In October 2001, HECO and the Consumer Advocate finalized agreements, subject to PUC approval, for the continuation of HECO's three commercial and industrial DSM programs and two residential DSM programs until HECO's next rate case. These agreements were in lieu of HECO continuing to seek approval of new 5-year DSM programs and provided that DSM programs to be in place after HECO's next rate case are to be determined as part of the case. Under the agreements, HECO agreed to cap the recovery of lost margins and shareholder incentives if such recovery would cause HECO to exceed its current "authorized return on rate base" (i.e. the rate of return on rate base found by the PUC to be reasonable in the most recent rate case for HECO). HECO also agreed it will not pursue the continuation

October 2001, HELCO and MECO reached similar agreements with the Consumer Advocate and filed requests to continue their four existing DSM programs.

In November 2001, the PUC issued orders (one of which was later amended) that, subject to certain reporting requirements and other conditions, approved (1) the agreements regarding the temporary continuation of HECO's five existing DSM programs until HECO's next rate case and (2) the agreements regarding the temporary continuation of HELCO's and MECO's DSM programs until one year after the PUC makes a revenue requirements determination in HECO's next rate case. Under the orders, however, HELCO and MECO are allowed to recover only lost margins and shareholder incentives accrued through the date that interim rates are established in HECO's next rate case, but may request to extend the time of such accrual and recovery for up to one additional year. In 2002, MECO's revenues from shareholder incentives were $0.7 million lower than the amount that would have been recorded if MECO had not agreed to cap such incentives when its authorized ROR was exceeded. Also in 2002, HELCO slightly exceeded its authorized ROR resulting in a reduction of revenues from shareholders incentives for 2002 by $31,000 (recorded in January 2003). In 2002, HECO did not exceed its authorized ROR. In 2003, none of the electric utilities exceeded their respective authorized RORs. In 2004, HECO and HELCO did not exceed their respective authorized RORs, but MECO exceeded its authorized ROR, resulting in a reduction of revenues from shareholders incentives and lost margins for 2004 by $1.0 million (recorded in December 2004).

One of the conditions to the temporary continuation of the DSM programs requires the utilities and the Consumer Advocate to review, every six months, the economic and rate impacts resulting from implementing the agreement. In reviewing HELCO's ROR for 2003, the Consumer Advocate raised an issue regarding Keahole settlement expenses and HELCO agreed to refund, with interest, all of the lost margins and shareholder incentives it had earned in 2003. In June 2004, HELCO recorded reduced revenues of $1.1 million to reflect the lost margins and shareholder incentives for 2003 that were refunded to customers in August 2004. No issues were raised regarding the lost margins and shareholder incentives earned by HECO or MECO in 2003.

In 2004, HECO and the Consumer Advocate reached agreement on a residential load management program and a commercial and industrial load management program and the PUC approved HECO's programs. Implementation of these programs began in early 2005. The residential load management program includes a monthly electric bill credit for eligible customers who participate in the program, which allows HECO to disconnect the customer's residential electric water heaters from HECO's system to reduce system load when deemed necessary by HECO. The commercial and industrial load management program provides an incentive on the portion of the demand load that eligible customers allow to be controlled or interrupted by HECO. In addition, if HECO interrupts the load, an incentive is paid on the kilowatthours interrupted. Customer incentives for the programs are expected to be approximately $1 million for the first full year and total $7 million over 5 years.

Avoided cost generic docket. In May 1992, the PUC instituted a generic investigation including all of Hawaii's electric utilities to examine the proxy method and the proxy method formula used by the electric utilities to calculate their avoided energy costs and Schedule Q rates. In general, Schedule Q rates are available to customers with cogeneration and/or small power production facilities with a capacity of 100 kilowatthours or less who buy/sell power from/to the electric utility. In addition to the electric utilities, the parties to the 1992 docket include the Consumer Advocate, the Department of Defense, and representatives of existing or potential independent power producers (IPPs). In March 1994, the parties entered into and filed a Stipulation to Resolve Proceedings, which is subject to PUC approval. The parties could not reach agreement with respect to certain of the issues, which are addressed in Statements of Position filed in March 1994. No further action was taken in the docket until July 2004, at which time the PUC ordered the parties to review and update, if necessary, the agreements, information and data contained in the stipulation and file such information and stated that further action will follow. The requested information will be submitted by the end of March 2005.

Collective bargaining agreements

Each of the electric utilities entered into a new four-year collective bargaining agreement in 2003 with the union which represents 59% of electric utility employees. See "Collective bargaining agreements" in Note 3 of the "Notes to Consolidated Financial Statements."

Hee, Alan K.

Subject: FW: 11/19/04 PBN follow up article on HECO rate case

EXCLUSIVE REPORTS
From the November 19, 2004 print edition

Hawaiian Electric Co. Inc. wants to get paid more for not producing electricity.

That's the essence of the utility's request for a rate increase.

And that's the main point of disagreement expected between HECO and state regulators who are reviewing the utility's approved by our regulators to serve those customers, still need to be recovered," said Lynne Unemori, HECO director of corporate communications. "If there were no lost margins, the utility would need to go in more often for rate increases to recover the rest of those fixed costs."

HECO's last rate increase was in 1995 for 1.3 percent.

The utility is basing its requested increase on estimated revenue requirements of $1.1 billion for 2005 yielding a 9.11 percent of return on HECO's average rate base.

Last year, the utility reported revenue of $960.7 million, up from $865.6 million in 2002.

HECO says its "demand side management programs" -- which encourage customers to use less energy -- are needed to lessen the impact of a dramatic increase in demand for power. The utility says it would rather get customers to use less than to build more power plants.

Cole said he doesn't believe HECO is losing out by encouraging ratepayers to use less energy.

"The load is increasing," he said. "If a person doesn't buy a kilowatt because they are conserving, somebody else is buying it. HECO is saying the peak loads are so high now they need conservation or they are not going to have enough power to go around."

Cole said he hasn't had time to thoroughly review HECO's rate request, but that he believes the logic behind the request doesn't add up.

"The lost margins and shareholder incentives aren't justified anymore when HECO is reaching record peak loads," Cole said. "When you have a lot of excess generating capacity and you are asking people to save energy, you are losing money because you could have sold that energy. Because HECO doesn't have excess generating capacity now, it's energy that's going to be sold. They need people to conserve in order to have enough for everybody."

Reach Terrence Sing at 955-8001 or tsing@bizjournals.com.

CA-IR-305

<u>Ref: HECO T-10, page 49.</u>

HECO states that the Company would not require regulatory approval to increase the DSM budget if DSM program costs were rolled into base rates.

a. Please confirm that the statement is based on the premise that inclusion of the DSM costs in base rates would put DSM expenditures on a par with, for example, distribution expenditures, which can be increased or decreased without Commission approval in response to changing system conditions.

b. If the premise described in subpart (a) of this information request is not correct, please accomplishments and cost-effectiveness. (See HECO T-10, page 48, line 22 through page 49, line 11, and page 50, lines 13-15.)

b. Not applicable.

CA-IR-306

Ref: HECO T-10, page 54.

Mr. Hee claims that the shortfall of $6,129,600 included in base rates is equal to the "annualized amount of fixed cost contribution to revenue loss from the implementation of DSM programs over a period of three program years." HECO 1023, however, shows that the quantity $6,129,600 is actually twice the annualized shortfall. If the Company is proposing to recover through base rates twice the annualized shortfall, please explain how this approach is consistent with the standard rate case practice given that this level of lost revenues will not be reached until 2007.

HECO Response:

The shortfall amount of $6,129,600 is equal to the annualized amount of fixed cost contribution to revenue lost from the implementation of DSM programs over a period of three program years less the shortfall embedded in base rates. The shortfall amount of $6,129,600 is also equal to twice the annualized shortfall for a single program year after the shortfall embedded in base rates has been subtracted. As shown in HECO-1023, the test year estimate of the shortfall amount recovered each year is equal to:

36-month shortfall for three program years:	$3,064,823 x 3 years* x 3 program years
- shortfall embedded in base rates	-$3,064,823 ÷ 2 x 6 years
÷ 3 years	÷ 3 years
	$3,064,823 x 2

* 2 half years + 2 full years

Thus, the Company is proposing to recover the equivalent of two-year's worth of the estimated fixed cost shortfall resulting from sales lost in one year. Note, however, that under the current mechanism, lost margins resulting from sales lost in one year are recovered for multiple years. Under the current lost margin mechanism, the lost margin for sales lost in 1996 have been recovered every year since 1996 because the Company continues to incur lost margins for those lost sales. The current lost margin recovery mechanism which recovers multiple years of lost margin was approved by the Commission in Decision and Order No. 13839, Docket No. 7257.

In this proceeding, the Company proposes to limit the recovery of the fixed cost contribution lost to two years rather than for multiple years as is permitted under the current lost margin mechanism. Further, in order to simplify the recovery mechanism, the Company proposes to levelize the recovery so that the amount of fixed cost contribution is the same each year (assuming that the annual sales reduction is constant). Thus, although this proposal recovers more than the estimated level of fixed cost shortfall in 2005 and 2006, it also caps the level of shortfall recovery so that it does not grow in future years as it would under the current mechanism.

The proposed lost margins that are embedded in the 3-year rolling average mechanism is a reasonable recognition of the impact of lost margins to the utility that helps the utility align its financial objectives with DSM policy objectives.

CA-IR-307

Ref: HECO T-10, page 56, lines 12-14.

a. Did Mr. Hee intend to say that the annualized three-year shortfall is $3,064,823?

b. If not, please explain.

HECO Response:

a. No.

b. The annualized three-year shortfall is $9,194,500 as stated in the above reference. In this case, the term "annualized" is meant to convey the fact that while the $9,194,500 is actually incurred in 2005, 2006, 2007, and 2008 (four calendar years), it is also equal to the shortfall

CA-IR-308

Ref. HECO T-10, page 57-58.

a. Regarding the proposed reconciliation clause, please clarify whether base rates will be adjusted to reflect the actual cost of DSM-related outside services that are incurred in 2005, if such cost is either less or greater than the estimated DSM-related costs included in the instant revenue requirement.

b. If no, please explain why not?

c. If yes, please explain the mechanism that will be used to adjust the base rates to "true up" the estimated DSM-related costs to actual.

HECO Response:

a. No, base rates will not be adjusted to reflect actual costs of DSM-related outside services incurred in 2005.

b. First, HECO intends to recover the actual costs of DSM-related outside services, along with other applicable DSM program-related costs that are incurred up to the effective date of the decision and order incorporating the DSM programs into base rates, through the DSM component of the IRP Clause. (See HECO T-10, page 62, lines 7 though 19.) Second, as stated on page 58, lines 6 through 17, the only component of program costs included in base rates that will be reconciled through the DSM reconciliation clause is customer incentives.

c. Not applicable.

CA-IR-309

Ref: HECO T-10, page 58.

Mr. Hee states that the reconciliation clause will have two components. Please explain how these two components will recover the costs of approved DSM programs not included in base rates. If possible, provide a numerical example.

HECO Response:

Please refer to HECO T-10, page 61, lines 11 – 18. The attachment on page 2 of this IR response is an example of how the DSM Reconciliation Mechanism would recover costs of approved DSM programs not included in base rates (e.g., the cost of DSM programs approved after the final D&O for this rate case) would be implemented. The attachment is a version of HECO-1025, but with lines 3a and 4a added to recover the cost of the DSM program(s) not included in base rates.

Hawaiian Electric Company, Inc.

Illustration of the DSM Reconciliation Clause

Line		Customer Incentives ($)		kWh Reduction*
1	Actual	9,000,000		40,000,000
2	Test Year	10,863,300		48,600,000
3	Difference	-1,863,300		-8,600,000
3a	**New DSM Program Cost**			**$2,000,000**
	Calculation of the DSM Reconcilation Surcharge			
4	Difference in Customer Incentives			-$1,863,300
4a	**New DSM Program Cost**			**$2,000,000**
5	Difference in kWh Reductions		-8,600,000	
6	Fixed Price per kWh (¢)		18.1	
7	Difference in Utility Incentive			-$1,556,600
8	Reconcilation Balance			-$1,419,900
9	Revenue Tax Multiplier			1.0975
10	Reconciliation Balance (Incl. Rev Taxes)			-$1,558,340
11	Annual Sales Excluding Sched F (gWh)			7,000.0
12	**DSM Reconcilation Adjustment (¢/kwh)**			**-0.020**

* Sales level, net of free-riders

Reference: HECO-1017, HECO-1024, HECO-1026

CA-IR-310

Ref: HECO T-10, page 62.

a. Will the proposed continuation of the Residential and C&I DSM adjustment components of the IRP Clause result in the double counting of some program costs and a higher effective return on program expenditures?

b. If so, please provide an estimate of the increased cost to customers due to these effects. If [redacted]

c. If no, please explain why not and also include a discussion as to how the Commission and Consumer Advocate will be able to ascertain that HECO is not allowed to recover some program costs twice. In the explanation, cite specific criteria and/or mechanisms, etc. will be applied to ensure that double recovery does not inadvertently occur.

HECO Response:

a. The proposed continuation of the Residential and C&I DSM adjustment components of the IRP Clause will not result in double counting some program costs, nor will it result in a higher effective return on program expenditures.

b. Not applicable

c. The shareholder incentives and CICR Program costs that will be recovered through the continuation of the Residential and C&I DSM adjustment components of the IRP Clause [redacted] the subsequent Annual Program Accomplishments and Surcharge ("A&S") report that reports actual program costs, lost margins, and shareholder incentives. The cost recovery of ongoing actual program costs, lost margins and shareholder incentives through the IRP Clause will terminate on the date that the Commission issues its decision and order incorporating the DSM programs into base rates. Because of the unique ex-post recovery for the CICR Program, only that portion of those costs associated with the shareholder incentives and CICR Program costs that are earned or incurred prior to the effective date of the rate case decision and order will be recovered through the continuation of the Residential and C&I DSM adjustment components of the IRP Clause.

CA-IR-311

Ref: HECO 1021.

Please provide the rationale for assuming that the Energy Solutions for the Home Program will produce the same lost revenue per MWh saved as the Residential Efficient Water Heating Program.

HECO Response:

Customers that are eligible to participate in the Energy Solutions for the Home ("ESH") Program (and the Residential Low Income Program), namely, existing residential customers, are the same customers that are eligible to participate in the Residential Efficient Water Heating ("REWH") Program (i.e. Schedule R customers). The other current residential DSM program for which actual lost margins are recovered is the Residential New Construction ("RNC") Program. However, the participants eligible to participate in the RNC Program are not the same as those eligible to participate in the ESH Program. RNC Program participants include both Schedule R customers and residential customers not on Schedule R, such as master-metered residential customers; in particular, military housing developments.

Program eligibility has an impact on the lost margin $ rate per MWH. The percentage of saved MWH from master-metered residential customers served under a commercial rate schedule is greater under the RNC Program than in the REWH Program. The lost margin $ rate per saved commercial MWH is lower than the lost margin per saved Schedule R MWH. This is the reason why the 2002 lost margin per MWH for the RNC Program is lower than the REWH Program. (This is due, in part, to new housing construction on military bases that is a major component of the RNC Program.) Therefore, because of the similarities in program eligibility for the ESH and REWH programs, it is reasonable to assume that the lost margin $ rate per MWH for the REWH Program is an appropriate estimation of the lost margin $ rate fore the ESH

Program absent historical data for the proposed ESH Program.

CA-IR-312

<u>Ref: HECO T-11, page 3, lines 3-4.</u>

a. Does provision 4) allow the Company to implement, without Commission approval, new measures not covered by the proposed new DSM programs described in Mr. Wikler's testimony?

b. If so, please cite the authoritative source which allows the Company to implement new DSM programs that have not been approved by the Hawaii Public Utilities Commission.

c. If not, please explain how HECO's proposed customer incentive budget flexibility provisions would allow the Company to add new measures and establish corresponding incentive levels to address market opportunities.

<u>HECO Response:</u>

a. Yes, however, as stated in HECO T-11, page 3, lines 5-8, HECO will inform the Commission of planned changes in program design and implementation in its Annual Modifications and Evaluation Report. The intent of the flexibility HECO is requesting in the referenced provision is to allow HECO to be able to quickly respond to advances in energy conservation measures between rate proceedings. For example, advances in fluorescent lamp technology have produced T-5 lamp fixtures that are considerably more efficient that the T-8 lamp fixtures that are currently eligible for customer rebates under HECO's existing Commercial and Industrial Energy Efficiency Program. HECO has requested the ability to offer customer rebates for T-5 fluorescent fixtures in this proceeding. HECO is requesting the flexibility to add individual energy efficient measures, not entire DSM programs, to respond more quickly to changes in technologies and in the marketplace, been approved by the Commission. HECO is only requesting the flexibility to add individual energy efficient measures to the approved DSM programs.

c. Please see HECO response to part a. above.

CA-IR-313

Ref: HECO T-11, page 4.

What is the basis of the Company's free rider estimates in its estimates of demand and energy reductions? Provide the assumptions, calculations, and results for each DSM program that resulted in the estimate of free riders.

HECO Response:

The table below lists the assumed free-rider rates for each of the programs. For HECO's existing programs, free-rider rates were derived from the 1998-1999 Impact Evaluation Reports. The 1998-1999 CIEE and CICR Programs Impact Evaluation Report was filed in a separate letter dated January 2, 2001 in Docket Nos. 94-0011 and 94-0012. The 1998-1999 CINC, REWH and RNC Programs Impact Evaluation Reports were filed as attachments to the November 30, 2001 Annual Program Modification and Evaluation Report in Docket Nos. 94-0010, 94-0011, 94-0012, 94-0206 and 94-0216.

For two of the new programs (Residential Low Income and Energy Solutions for the Home), the free-rider rates were derived from industry experience. For the RCEA program the free rider rates for both energy and demand are "Not Applicable" because the Company does not have an initial estimate of energy or demand impacts for the program. For the CIDLC and RDLC programs the free rider rates for the energy impacts are "Not Applicable" because the Company will not be claiming any energy impacts for DSM utility incentive purposes. The CIDLC and RDLC program free rider rates for demand impacts are assumed to be zero because the experience of other utilities who have implemented similar types of programs has been that without a utility interruptible or direct load control program customers would not consistently and reliably interrupt their loads.

	Program	Free-Rider Rate	
		Energy	Demand
Elxsting Programs	Commercial and Industrial Energy Efficiency	35%	34%
	Commercial and Industrial New Construction	40%	39%
	Commercial and Industrial Custom Rebates	24%	25%
	Residential Efficient Water Heating	27%	27%
	Residential New Construction	16%	12%
New Programs	Residential Consumer Energy Awareness	NA	NA
	Residential Low Income	0%	0%
	Energy Solutions for the Home	15%	15%
	Commercial and Industrial Direct Load Control	NA	0%
	Residential Direct Load Control	NA	0%

CA-IR-314

Ref: HECO 1102, Appendix E.

Please provide electronic spreadsheets, with all formula and cell references intact, for the benefit / cost calculations provided in this exhibit for each individual program included in the Company's DSM portfolio. Please provide copies of all workpapers containing the computations that support the numbers presented in this document, and specify all assumptions made in performing such calculations, including the fuel and capital cost projections used in each assessment and the dates such projections were prepared.

HECO Response:

The Excel spreadsheets will be provided under separate transmittal. Note that many of the assumptions that supported the benefit / cost analysis for the Phase II report were made in the second quarter of 2004, well in advance of the preparations for this testimony. Subsequent to the preparation of the Phase II report, modifications were made to the benefit / cost calculations to reflect a number of refined assumptions that result in the benefit / cost calculations included in HECO-1104. The modified spreadsheets have been provided as part of HECO's rate case application.

CA-IR-315

a. For each of the cost-benefit tests referenced in the above information request pertaining to HECO 1102, Appendix E, state whether the following costs are included or excluded: (i) utility incentives excluding lost revenues; (ii) lost revenues; (iii) customer service costs excluding customer incentives; (iv) customer incentives; and (v) utility administrative and overhead costs including M&E costs.

b. If not provided in the electronic spreadsheets, please provide an estimate of each of these costs for each program analyzed.

c. Please also state whether the level of customer incentives used in each test is reflective of current or future incentive levels.

HECO Response:

a. Please see page 2 of this response.

b. All costs referenced above are provided in the electronic spreadsheets.

c. The level of customer incentives used in each cost-benefit calculation was reflective of projected future incentive levels. The incentive levels for existing programs were based on

Costs Included (Excluded) in DSM Program Cost Benefit Tests

Cost Benefit Test	Utility Incentive Excluding Lost Revenues	Lost Revenues	Customer Service Costs Excluding Customer Incentives	Customer Incentives	Utility Admin and Overhead including M&E Costs
Participant	Excluded	Included as Participant Savings	Excluded	Included	Excluded
Ratepayer Impact Measure	Excluded[1]	Included	Included	Included	Included
Utility Cost	Excluded[1]	Excluded	Included	Included	Included
Total Resource Cost	Excluded[1]	Excluded	Included	Included	Included

Note: 1. Utility incentives excluding lost revenue were not included in the preliminary analysis of cost-effectiveness conducted in HECO-1102. However, with the exception of the load management programs, they were included in the cost benefit tests referenced in HECO-1104.

CA-IR-316

Ref: HECO T-11, page 12, lines 5-14.

Is the Company's proposal to recover through base rates evaluation costs incurred outside of the test year consistent with Commission base rate case practice? Please discuss.

HECO Response:

Yes. Test year expenses represent expenses incurred in a normalized test year. Evaluation costs vary by year in a typical DSM program cycle. For example, in the first year of a typical DSM program very little evaluation costs will be incurred as participation commences. In year two, participation will be sufficient to create a representative sample and to begin equipment metering and data collection. Consequently, evaluation costs in year two are significantly greater than in year one.

Evaluation costs in the existing DSM programs are recovered through the IRP surcharge recovery mechanism. In this way only the costs that were actually incurred are recovered. In this proceeding HECO is requesting to include evaluation costs in base rates. Therefore, it is necessary to normalize the uneven costs. This was done by forecasting evaluation costs over a typical five year DSM program cycle. These costs were then summed and total was divided by 5. HECO maintains that this method of normalizing uneven costs is reasonable.

CA-IR-317

<u>Ref: HECO T-11, page 33.</u>

Regarding the statement that HECO will pay the demand incentive for any customer demand reduction, please describe how such demand incentive payments are to be calculated, and how HECO will ensure that such incentive will be cost effective.

<u>HECO Response:</u>

[redacted]

peak electrical usage period of 5:00 pm to 9:00 pm, weekdays. Consequently, a customer

CA-IR-318

Ref: HECO T-11, page 81.

At line 20, Mr. Wikler states the 2005 estimate for the cost of the residential direct load control program is $2,880,959. HECO 1004, however, shows a cost of $2,042,000 for residential direct load control. Please explain this discrepancy.

HECO Response:

HECO-1004 presents the Forecast Adjustments between the 2005 Operating Budget and the 2005 Test Year Estimate. For the RDLC Program, the 2005 O&M Operating Budget was $795,202 and the 2005 Capital Equipment was $2,527,280. (See response to CA-IR-2, HECO T-11, Attachment 1, page 11.) For the 2005 Test Year Estimate, labor was increased by $43,911 (see HECO-1004, line 4) and the capital equipment was transferred to O&M, resulting in the non-labor increase of $2,041,846 (see HECO-1004, line 11) resulting in the $2,085,757 adjustment. Therefore, the $2,042,000 referenced above represents only the non-labor difference between the 2005 Operating Budget and the 2005 Test Year Estimate. The total RDLC Program 2005 Test Year Estimate is $2,880,959.

CA-IR-319

Ref: HECO T-12, page 3.

Mr. Violette says that his testimony addresses the economic rationale underlying appropriate financial treatment of investments in DSM programs. If the term "investments in DSM programs" includes DSM expenditures that currently are booked to expense accounts, please explain why such expenses deserve a different ratemaking treatment than other HECO expenses (e.g., purchased energy).

HECO Response:

The term "investments in DSM programs" encompasses all costs spent implementing DSM. The specific DSM expenditures booked to expenses would not be given any special treatment in themselves. However, the unique aspect of DSM investments, regardless of classification, is that they result in reduced revenues that would otherwise have been achieved by the utility. The opportunity costs forgone by HECO in terms of earnings potential, and the fewer kWh on which to recover fixed costs are the issues that give rise the need for incentives.

CA-IR-320

<u>Ref: HECO T-12, page 7, lines 10-11.</u>

a. Given HECO's need to add new resources to meet strong load growth, why does Mr. Violette believe the Company must receive positive incentives beyond direct cost recovery of the Commission approved DSM programs to encourage implementation of cost-effective DSM programs?

b. In other words, why would the opportunity to implement cost-effective DSM programs to fulfill basic service obligations not be sufficient encouragement?

c. Is Mr. Violette saying that, absent DSM incentives, HECO likely will choose to make more costly and perhaps riskier supply-side investments?

<u>HECO Response:</u>

a. The witness' testimony is that it is a matter of good public and regulatory policy to provide positive incentives so that investments in suitable and effective demand-side management programs are at least as attractive to the utility as investments in supply-side options. Load growth, coupled with the time required to implement new supply-side resources, provide an incentive to a utility to pursue demand-side resources, at least in the short-run. But that does not mean that requiring the utility to accept uncompensated risks as its "reward" for meeting its service obligation is good public or regulatory policy. That would be comparable to arguing that a utility should not be compensated for costs incurred in restoring its system after a natural catastrophe, because the utility needs to restore its system anyway in order to measures in the late 1980s and 1990s, meant that some load growth could be cost-effectively met through the implementation of utility-sponsored conservation programs. This is similar to building a conservation-based power plant. The utility has to develop infrastructure, design a product/program, put in place a marketing plan, and build a fulfillment strategy/capability. In essence, the allocation of component costs for an energy efficiency program may differ from that of more traditional supply-side alternatives; but, the energy efficiency program, like the supply-side alternatives, should also be provided with the opportunity to earn a return on investment so that 1) investments in suitable and effective demand-side management programs are at least as attractive to the utility as investments in supply-side options, and 2) the utility can fulfill its financial responsibility to its investors.

Mr. John Rowe, currently the CEO of Exelon (parent company to ComEd and PECO), wrote in the preface to the landmark National Association of Regulatory Commissioners (NARUC) publication "Profits and Progress through Least-Cost Planning," David Moskovitz, NARUC, November 1989 that:

problem can be increased oversight by the Hawaii PUC and a greater reliance on command and control regulation. However, most PUCs have limited resources to monitor utility behavior, and the adoption of incentives that re-enforce the desired utility behavior without the imposition of intense regulatory oversight (due to having to overcome the negative [redacted]

Finally, successful DSM depends on the innovation and commitment of the utility and this is [redacted] implement a regional least-cost plan was stymied by a disagreement over appropriate

incentives:

<u>Snohomish PUD Slashes Conservation</u>

The Snohomish County Public Utility District, an electric utility in Everett, Washington, unexpectedly dropped its conservation plans for 1994 after failing to negotiate a new contract with Bonneville Power Administration (BPA) for a "conservation power plant." A chief

> being assured of cost recovery. Slowly, lashed by the misused slogan 'duty to serve,' utilities respond, but the results are credible to no one." (Source: Foreward to "Profits & Progress through Least-Cost Planning," published by the National Association of Regulatory Utility Commissioners, November 1989).

Mr. Rowe's statement that utilities are -- "lashed by the misused slogan 'duty to serve' … the results are credible to no one" -- provides the strong signal that this utility CEO, without directly pointing the finger at other CEOs, indicates that investments in energy efficiency may not approach optimal levels without positive incentives.

Also, one can look at the U.S. Energy Information Administration's data on recorded investment in DSM to see that the downward trend industry-wide in DSM that accompanied the changes in incentives of the late 1990's and early 2000's. It is exactly this dip that is in the interest of HECO and its ratepayers to avoid.

Finally, the recent report on <u>Hawaii Energy Utility Regulation and Taxation</u>, Hawaii Energy Policy Forum, July 2003, as quoted on page 27 of HECO T-12, suggests concerns about how aggressively utility management might pursue DSM if the current financial mechanisms are ended. The authors stated in this report:

> "Unless these financial mechanisms are replaced with some form of mandate or alternative incentives, the current DSM programs are in serious jeopardy. … The mechanisms being terminated quietly by the PUC were previously established by several years of collaborative efforts by Hawaii's energy sector stakeholders."

In summary, while it is not possible to speculate what actions HECO might take, there is evidence that incentives make a difference in the level of commitment to investments in energy efficiency. Working out a set of financial mechanisms whereby the utilities least cost plan is also their most profitable plan makes good sense. Appropriate alignment of incentives is simply good public policy.

CA-IR-321

<u>Ref: HECO T-12 pages 13–15.</u>

Please provide copies of each decision or resolution referenced on pages 13-15.

HECO Response:

The following decisions or resolutions, attached as pages 2 through 362, are listed as follows:

- Resolution on State Commission Responses to the Natural Gas Supply Situation, July 2003 (pgs. 2-3)
- Resolution on Gas and Electric Energy Efficiency, July 2004 (pgs. 4-5)
- State of California Energy Action Plan, May 8, 2003 (pgs. 6-17)
- State of California Public Utilities Commission Decision No. 03-06-032, June 6, 2002 (pgs. 18-131)
- State of New Jersey Board of Public Utilities Energy Final Decision & Order (pgs. 132-209)
- State of New Jersey Energy Final Order, May 17, 2004 (pgs. 210-362)

Due to the voluminous nature of the information, one copy (pages 2 – 362) will be provided to the Consumer Advocate, Department of Defense and the Public Utilities Commission under separate transmittal.

CA-IR-322

Ref: HECO T-12, page 20.

Please provide copies of the recent state commission decisions referenced at lines 12-13.

HECO Response:

Recent state commission decisions are attached from pages 2 – 55 and are listed as follows:

- Minnesota Public Utilities Commission Order Approving Demand Side Management Financial Incentive Plans, April 7, 2000, pgs. 2-19.
- State of Connecticut Department of Public Utility Control Draft Decision, July 1, 2004, pgs. 20-47.
- Kentucky Utilities Commission Demand-Side Management Cost Recovery Mechanism, July 20, 2004, pgs. 48- 53.
- Commonwealth of Kentucky Public Service Commission Order, March 25, 2004, pgs. 54-55.

The following decisions were submitted in response to CA-IR-321.

- State of California Public Utilities Commission Decision No. 03-06-032, June 6, 2002.
- State of New Jersey Board of Public Utilities Energy Final Decision & Order.
- [illegible]

ISSUE DATE: April 7, 2000

DOCKET NO. E,G-999/CI-98-1759

ORDER APPROVING DEMAND SIDE MANAGEMENT FINANCIAL INCENTIVE PLANS

BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

Gregory Scott	Chair
Edward A. Garvey	Commissioner
Joel Jacobs	Commissioner
Marshall Johnson	Commissioner
LeRoy Koppendrayer	Commissioner

In the Matter of Requests to Continue Demand-Side Management Financial Incentives Beyond 1998

ISSUE DATE: April 7, 2000

DOCKET NO. E,G-999/CI-98-1759

ORDER APPROVING DEMAND SIDE MANAGEMENT FINANCIAL INCENTIVE PLANS

PROCEDURAL HISTORY

On December 2, 1998, the Commission convened a Chair's Round Table: 1) to evaluate the success of recent gas and electric utility DSM efforts in achieving cost effective conservation and to identify further DSM programs and methodologies that effectively conserve energy; and 2) to re-evaluate the need for gas and electric DSM financial incentives, and make a recommendation for elimination or redesign. See Commission 's December 2, 1998 Order in Docket No. E-999/ CI-98-755.

On September 20, 1999, several of the parties who had been meeting to develop principles for revised DSM financial incentive plans filed a joint letter with the Commission reporting on the parties' progress and indicating that they wanted to discuss further the details of revised incentive plans. The parties also stated that utilities planned to file individual proposals for plans based on agreed-to principles.

On November 1, 1999, the Department filed a Joint Proposal (Joint Proposal) for a Shared-Savings DSM Financial Incentive Plan (Plan) on behalf of itself and the following parties: Izaak [illegible]

In effect, the utilities' November 8, 1999 filings (spreadsheets) constitute (in conjunction with the Joint Proposal) their proposed DSM incentive plans for 1999 and beyond. NSP-Electric additionally sought approval of its load management discount program as part of its new DSM incentive plan.[1]

On December 6, 1999, the Department filed modified spreadsheets regarding five companies: Alliant Energy, Reliant Energy Minnegasco, Otter Tail Power Company, NSP-Gas, and Great Plains Natural Gas Company. The Department stated that the utilities involved had agreed to the recalculation of the incentives as shown on the modified spreadsheets. The Department recommended the Commission approve the jointly proposed plan, with the supporting spreadsheets, as modified in its December 6, 1999 filing. In a separate set of comments also filed on December 6, the Department recommended that the Commission reject NSP-Electric's proposal to continue recovery of a portion of the Company's load management rate discounts.

On December 6, 1999, the OAG filed comments on the Joint Proposal. The OAG stated that it supported the overall concept of the Joint Proposal, but recommended three specific changes:

1. no bonus payment to utility for meeting the legislatively mandated CIP spending level ;

2. capping the total bonus payment at 15% (instead of 30%) of actual CIP spending; and

3. a Commission review for accuracy and consistency of the avoided cost used to calculate the bonus.

In addition, the OAG indicated that it did not support the continuation of NSP-Electric's load management discount rate recovery.

On December 6, 1999, Lund Food Holdings, North Star Steel, and the Suburban Rate Authority (the Large Customers), represented by Dahlen, Berg & Company filed

- comments in Docket No. E-002/M-99-508 regarding NSP's proposed DSM incentive plan for 1999 and beyond;

- comments in Docket No. E-015/M-99-538 regarding MP's proposed DSM

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[1] The individual utiities filed their individual incentive plans for 1999 and beyond in the following dockets: G-004/M-99-535 (Great Plains Natural Gas Company); E-001/M-99-537 (Interstate Power/Alliant); E-015/M-99-538 (Minnesota Power); G-007/M-99-549 (Northern Minnesota Utilities); E-002/M-99-508 (Northern States Power Company-Electric); G-002/M-99-550 (Northern States Power Company-Gas); E-017/M-99-510 (Otter Tail Power Company); G-011/M-99-548 (Peoples Natural Gas Company); and G-008/M-99-509 (Reliant Energy Minnegasco).

incentive plan for 1999 and beyond; and

- comments in Docket No. E-017/M-99-510 regarding OTP's proposed DSM incentive plan for 1999 and beyond.

In each of their comments, the Large Customers objected to the Joint Proposal for a new DSM Financial Incentive Plan filed November 1, 1999. However, the Large Customers also commented that if the Commission allows an incentive, the following guidelines should apply:

1. total incentive payment should be capped at 10% of actual CIP spending;

2. incentive award should be tied to utility earnings levels; and

3. incentive proposal should include a sunset clause.

On December 16, 1999, the Department, NSP, Reliant, and CEE/IWLA filed comments replying to the changes proposed by the OAG and the Large Customers. In addition, NSP filed further support for its load management discount recovery and the OAG filed comments explaining further its recommendations.

The Commission met to consider this matter on January 27, 2000.

FINDINGS AND CONCLUSIONS

I. THE JOINTLY PROPOSED DSM FINANCIAL INCENTIVE PLAN

The Proponents requested Commission approval of a Shared-Savings Demand Side Management (DSM) Financial Incentive Plan (the Plan) to be applied voluntarily to all gas and electric utilities that participate in the Department's Conservation Improvement Program (CIP). The Plan is intended to replace the current incentive plans and apply to CIP activities beginning with the 1999 project year. The Plan is the product of a series of work group meetings initiated and facilitated by the Department. The meetings were attended by all the parties to this docket, including the OAG and the Large Customers, represented by Dahlen, Berg & Company.

According to the Proponents, the Plan provides utilities with a reasonable and effective incentive to increase cost effective utility investment in DSM beyond the spending level required by statute.

A key provision of the Plan is the method for determining a utility's **Incentive Energy Savings Goal**, i.e. the energy savings goal that the Plan uses for incentive calculation purposes. Under the Plan, each utility's **Incentive Energy Savings Goal** is calculated by the same formula: it is the product of the company's Department-ordered CIP Energy Savings Goal divided by the company's Department-approved CIP Budget multiplied times the company's statutory minimum

CIP spending level.[2]

Proponents emphasized that the Plan does not award the utility incentives simply for complying with statutory spending requirements. Nor does the Plan create an incentive based on the amount of its CIP **expenditures** without regard to cost effectiveness or ratepayer benefit. Instead, it requires a finding that those expenditures have resulted in **net ratepayer benefits**[3] and awards only a **portion** of any such **net ratepayer benefits** to the utility. Consequently, the vast majority of the net ratepayer benefits resulting to the utility's DSM expenditures will accrue to the ratepayers.

According to the Plan, a utility begins to earn incentive payments when it surpasses 90 percent of its **Incentive Energy Savings Goal**. The Proponents explained that the monetary reward (incentive) for attaining 91-100 percent of the goal is small but is deemed helpful in motivating utilities to move beyond 100 percent of the goal. Under the Plan, the size of the incentive increases at every percentage point above 90 percent of goal but never exceeds the amount of ratepayer benefit and is capped at 30 percent of the utility's Department-approved CIP expenditure level or 30 percent of a utility's actual CIP expenditures.

The Plan provides for regular reviews of the utilities' plans in light of their actual achievements. The Plan calls for Commission review of each utility's individual DSM Incentive Plan during the second year of each utility's biennial CIP filing. The reviews are to be conducted in the context of the consolidated CIP tracker account filings, which means that the utilities' plans would be reviewed with complete information on file regarding the individual utilities' actual energy savings achievements.[4] The Plan provides that reviews for electric utilities are to be conducted in the Spring of 2001 and in the spring of 2002 for the gas utilities. The utilities' plans would be evaluated in light of their actual energy savings and the four statutory criteria (Minn. Stat. §

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[2] To illustrate: Otter Tail Power Company has a Department-ordered 1999 CIP Energy Savings Goal of 9,268,186 kWh, a Department-approved 1999 CIP Budget of $1,488,144, and a statutory minimum CIP spending requirement of $1,417,504. Plugging these figures into the proposed formula produces the following **Incentive Energy Savings Goal** for OTP: 8,828,239 kWh.

[3] Under the Plan, net ratepayer benefits are calculated based on the utilities' estimate of the avoided costs that will result from each of their CIP expenditures. The companies' avoided cost estimates appear in the utilities' 1999-2000 DSM Incentive Plans, i.e. in their November 8, 1999 filings, which detail the application of the Proponents' Plan to their individual CIP Programs.

[4] The utilities would continue to make their incentive filings in April or May of each year. As part of these filings, the utilities would report their actual energy savings achievements and request authority to recover a specific amount of incentive through the CPA over the coming fiscal year. In reviewing such proposals, therefore, the Commission will have before it the utilities' actual savings achievements.

216B.16, subd. 6c) and would be retained, modified or prospectively terminated for the following biennium.

In addition, the Proponents proposed that the utilities submit compliance filings by February 1 of each year (similar to the filings they made November 8, 1999) showing how the incentive mechanism will work for the utility during the coming fiscal year given the utility's Commissioner-approved Conservation Improvement Program (CIP) budget and energy saving goal.

In sum, the Proponents supported the Plan by arguing that the Plan meets the four criteria for such incentives established by Minn. Stat. § 216B.16, subd. 6c and overcomes the objections of various parties to previous financial incentive plans.

II. THE LARGE CUSTOMERS' CRITICISMS OF THE PLAN

In response to the Commission's November 2, 1999 notice extending the comment period, the Large Customers filed comments in three dockets: Docket No. E-002/M-99-508 (NSP's DSM financial incentive plan); Docket No. E-015/M-99-538 (MP's DSM financial incentive plan); and E-017/M-99-510 (OTP's DSM financial incentive plan). In effect, the Large Customers'

criticisms of these utilities' individual DSM incentive plans apply to various aspects of the Proponents' Plan and, therefore, will be discussed as such.

A. Large Customers' Recommendation to Reject the Plan

The Large Customers argued that the companies' proposed conservation incentive plans did not meet three of the four the statutory standards established in Minn. Stat. § 216B.16, subd. 6c and should, therefore, be rejected.

Standard #1: a conservation plan should be likely to increase utility investment in cost-effective conservation. The Large Customers asserted that the Proponents have provided no support for the notion that the proposed incentive will result in increased investment in cost-effective conservation. The Large Customers noted that experience under the current incentive package showed that as the incentive amount increased, the conservation investment decreased.
The Commission finds that the proposed incentive differs from the current incentive so substantially that the Large Consumers' argument based on the recovery/expenditure experience under the previous incentive is not persuasive.

First: much of the uncontrolled growth of incentive recovery under the previous plans was due to the fact that recovery of lost margins was cumulative. That is, under the previous incentive plan, once an amount of lost margins was determined to have occurred, it continued to be recovered in each subsequent year regardless of whether they were offset by sales growth in other areas. This feature (cumulative recovery of lost margins) has been eliminated from the proposed incentive, which is awarded based strictly on the amount of net ratepayer benefits (not lost margins) created in the instant year.

Second: under the proposed Plan, the size of the incentive increases for each incremental block of energy savings. The Proponents stated that the increasing increments of the incentive established in the Plan will motivate utilities to exceed savings achievable at statutory spending levels and will result in increased utility investments in cost-effective energy conservation. This approach appears plausible to the Commission, which, of course, will be able to monitor actual results in the reviews provided for under the Plan and modify the Plan as necessary.

Standard #2: The Large Customers asserted that the incentives for NSP ($15 million), MP ($1.64 million), and OTP ($45,000) for 1999 are excessive and not compatible with the interests of ratepayers. Furthermore, the Large Customers argued that recovery of these amounts may allow the three utilities to earn more than their allowed rate of return, and thus the recoveries would represent a windfall to utility shareholders.

The Commission finds, however, that allowing utilities to recover a portion of the net benefits produced by cost-effective conservation expenditures is in the ratepayers' interest. Cost-effective conservation expenditures result in environmental benefits which ratepayers receive as well as the rest of society, and they specifically benefit ratepayers because such expenditures avoid the need for more expensive supply-side investments which ratepayers would eventually be obliged to pay for.

The Large Customers also argued that a utility's recovery of incentive above its allowed rate of return would represent a windfall to shareholders. After examining the details of the proposed incentive, the Commission does not accept the Large Customer's view. In two recent Orders, the Commission denied the recovery of DSM financial incentives by utilities whose earnings, even without counting the financial incentives in question, exceeded their authorized rate of return.[5] In its Orders, the Commission specifically cited the companies' earning levels as a pivotal factor in the Commission's determinations that recovery of additional amounts (the financial incentives in question) would not be just and reasonable.

These Orders are fact-specific, however, and do not stand for the proposition that the Commission would, under no circumstances, adopt an incentive recovery plan that would provide recovery of financial incentives without regard to earnings, i.e. irrespective of whether the utility had earned beyond its authorized rate of return.

In the current docket, the Commission has considered a Joint Proposal which makes substantial revisions in the way incentives for DSM achievement will henceforward be calculated and awarded. The Joint Proposal is the product of a series of work group meetings initiated and facilitated by the Department. In the course of these meetings, the parties conducted a major review of DSM incentives participated in by the major stakeholders in this subject.[6] Major improvements over the former incentive plans include the fact that the incentives are not cumulative as was the case previously.

Instead the incentives proposed at this time are based strictly on the net benefits created in the instant year. Absent growth in new cost-effective conservation spending and resulting ratepayer benefit, the incentive will not grow over time. In addition, the incentive is designed to motivate spending **beyond** the statutorily required level and always remain a small **portion** of the net benefits created so ratepayers always benefits much more than the shareholders.

Standard #4: The Large Customers argued that the proposed Plan does not meet the fourth standard (that the incentive plan not conflict with other provisions of Chapter 216B) because allowing utilities to recover incentives in addition to their authorized rate of return results in rates that are not just and reasonable as required by Minn. Stat. § 216B.03. The Commission has addressed the substance of this objection above in explaining why, considering the totality of circumstances changed by the revised incentive proposed in this matter, the earnings issue is not pivotal in this case.

In sum, the Commission finds that incentive amounts authorized by the Plan will impose only modest costs on ratepayers, appropriately motivate utilities to increase cost-effectiveness of their CIP Programs above statutory requirements, consistently require the achievement of net ratepayer benefits, and consequently result in just and reasonable rates.

B. Large Customers' Recommendation to Modify the Plan

The Large Customers suggested in the alternative that if the Commission approved a CIP incentive for NSP, MP, and OTP, the Commission should modify the incentive to better balance utility and ratepayer interests. Specifically, the Large Customers recommended that the Commission reduce the cap on incentive recovery, institute an earnings test, set a sunset date on the companies' plans, and reduce their current CPA surcharges to collect no more than the authorized DSM incentive.

1. Cap on Incentive Recovery

The Commission will not reduce the cap on total incentive payments, which the Proponents have proposed as 30 percent of the Department-ordered CIP spending or 30 percent of actual CIP spending, whichever is less. The Commission notes that the size of the incentive is always calculated as a **portion** of net ratepayer **benefits** so the amount of ratepayer benefit will always

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effective DSM investments (expenditures) above statutory mandated levels and even this party modified its opposition, acknowledging that the Joint Proposal is a significant improvement over previous incentive plans. The Large Customers hedged their opposition further by proposing an incentive plan of its own, thereby acknowledging the usefulness and appropriateness of financial incentives under certain conditions. The other party not completely supporting the particulars of the Joint Proposal, the OAG, clearly stated its support for the overall concept of the Joint Proposal. The Commission discusses the positions of these two parties extensively in the text of this Order.

substantially exceed the amounts paid to the utility. Given this arrangement, the size of the cap on incentive payments is not a major concern and the Commission cannot find that the 30 percent figure agreed upon by the Proponents is unreasonable.[7]

2. Earnings Test

The Large Customers' proposal to impose an earnings test has been discussed previously in this Order and found unnecessary due to the substantial changes in the proposed incentive over the previously approved incentives.

3. Sunset Date

A sunset date for the Plan is unnecessary in light of the extensive monitoring provisions required by the Plan. The Plan calls for Commission to review each utility's individual DSM Incentive Plan during the second year of each utility's biennial CIP filing. In these reviews, the Commission will evaluate the utilities' plans in light of the four statutory criteria established in Minn. Stat. § 216B.16, subd. 6c. The utilities' plans will be retained, modified or terminated in accordance with that review. To provide additional Commission oversight, the utilities will submit a compliance filing by February 1 of each year containing the budgets, energy savings, and a recap of how the incentive mechanism will work for the utility that year given the utility's Commissioner-approved CIP budget and energy saving goal.

4. Modification of the CPA

Regarding proposed revision of the utilities' current CPA surcharges, NSP has already been directed to adjust its CPA surcharge in keeping with the Commission's July 27, 1999 and February 18, 2000 Orders in Docket No. E-002/M-99-419. As for MP's and OTP's CPA surcharges, on or about May 1, 2000 these companies will be proposing their new CPA surcharges consistent with this Order for the CIP year commencing July 1, 2000. Moreover, recovery through the CPA surcharge is subject to true-up provisions which adjust for any over- or under-recovery of CIP incentives which the companies may experience.

Under these circumstances, no special additional filing to adjust the utilities' CIP surcharges need be ordered at this time.

III. THE OAG'S PROPOSED MODIFICATIONS OF THE PLAN

The OAG supported the overall concept of the proposed incentive (a non-cumulative portion of net ratepayer benefit) but criticized three variables in the Plan: 1) the point (trigger) at which the utility begins to accrue incentives; 2) the cap on total incentive payments; 3) calculation of the

A. Trigger of Incentives

Under the Plan, a utility earns a small incentive once it achieves 91 percent of its **Incentive Energy Savings Goal** (as that term is calculated pursuant to the Plan) and earns a slowly increasing amount of incentive with each additional percentage point of the Incentive Energy Savings Goal that it achieves. To the extent that this results in awarding any incentive before the utility achieved the energy savings level ordered by the Commerce Commissioner, the OAG objected. There are two parts to the OAG's objection:

1. The OAG's Objection to Establishing an Incentive Energy Savings Goal as the Common Baseline for Each Utility

The OAG objected to the Proponents' creation of a new factor, the "Incentive Energy Savings Goal" (see discussion and formula above at page 3) as the starting point (trigger or baseline) for incentive calculations. The OAG favored using the DSM energy savings level ordered by the Commissioner as the point at which incentives would begin to be awarded.

The Commission finds that the Plan's proposed definition and use of an Incentive Energy Savings Goal (as distinguished from the statutorily required CIP spending level and the Commissioner-directed Energy Savings Goal) is appropriate. The problems overcome by using the newly designated Incentive Energy Savings Goal are these:

> 1) since the purpose of the CIP expenditures is to achieve energy savings (avoided cost and ratepayer benefit) it is helpful to define a baseline in terms of the result sought, i.e. kWh saved energy, rather than in terms CIP spending levels;[8] and
>
> 2) seeking a fair and uniform baseline applicable to all utilities rules out using the Commissioner-directed Energy Savings Goal because in setting that Goal the Commissioner takes into account the utilities' differing historical and legal circumstances, which results in substantially different Energy Savings Goals for each utility.

The Proponents' proposal takes these practical problems into account and presents a formula for

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[8] Minn. Stat. § 216B.241 (the Energy Conservation Statute) specifies Subd. 1a a formula for calculating the **CIP spending level** required of each regulated utility, i.e. the statute requires the utility to expend a specified percentage of its gross operating revenues on energy conservation improvements) but authorizes the Commissioner of the Department of Commerce to require expenditures above that level (Minn. Stat. § 216B.412, Subd. 2) and directs the Commissioner to set **energy-saving goals** to be achieved through those expenditures but does not provide a specific formula for doing so (Minn. Stat. § 216B.241, Subd. 1c).

the Incentive Energy Savings Goal[9] that provides a fair baseline for purposes of awarding incentives.

2. The OAG's Objection to Awarding Incentives to a Utility Before the Utility Has Achieved 100 Percent of its CIP Obligations

The OAG argued that all utilities should satisfy their legal CIP obligations (both statutory spending levels and Commissioner-ordered energy savings) and not receive a financial incentive for doing so. However, the Commission is persuaded by the Proponents that allowing incentive recovery to begin at 91 percent of Incentive Energy Savings Goal and increasing that amount slowly with each additional percentage of Goal achieved is more likely to result in additional cost-effective expenditures than if incentives are withheld until the utility achieves 100 percent of its Incentive Energy Savings Goal.

The Commission's initial inclination (similar to the OAG's) is that utilities should not be rewarded for performing a legal obligation. However, the Commission's concern is mitigated by the fact that the incentive for attaining the 91-100 percent level is quite small and its concern is completely overcome by the realization that beginning to allow recovery at the 91 percent level is consistent with the basic purpose of awarding incentives in the first place, i.e. to motivate cost-effective CIP expenditures **beyond** the legislated level. In fact, the Commission has come to understand that awarding minimal incentives for achieving the 91-100 range is a practical motivator for utilities to achieve 100 percent of the Energy Savings Goal, not as an end in itself, but as an important point on the road to the ultimate goal: **additional** (above the statutory requirements) cost-effective (ratepayer benefitting) conservation expenditures.

Attaining the 100 percent goal is critical because once utilities reach that level, incentives for further achievement become substantial, and the steadily increasing incentive amounts within reach at that point will strongly motivate them to keep increasing their CIP expenditures and (because incentives are awarded on the basis of net ratepayer benefit) to do so in the most cost-effective manner. The concern is that if the incentive is started too late, the utilities may not reach the 100 percent level, i.e. the place where the larger (post 100 percent) incentives would be close enough to affect them.

In short, the Commission concludes that awarding modest but steadily increasing incentives beginning at 91 percent of the Incentive Energy Savings Goal (as recommended by the Proponents) is a small price to pay and a reasonable strategy to avoid the risk of adopting incentives that start so late that they are ineffective.

B. Cap on Total Incentive Payments Allowed Under the Plan

The Proponents proposed to cap the amount of incentive that a utility could earn at 30 percent of the utility's Department-approved CIP expenditure level or 30 percent of the utility's actual CIP

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[9] Described above at page 3.

expenditure, whichever was lower. The OAG proposed to reduce the cap to 15 percent of the utility's total CIP expenses. The OAG objected that the Proponents' cap was too high and that, as a consequence, utilities could be earning an excessive return on their CIP investments, particularly in light of the fact that there is little or no risk to the utility under the proposed incentive structure.

But since the relevant CIP expenditures must be cost effective and a utility will always be limited to receiving a small portion of the net ratepayer benefit generated by the CIP expenditure, incentives up to 30 percent of CIP expenditures (or 30 percent of Department-approved CIP expenditures) do not appear excessive.

Further demonstrating the reasonableness of the 30 percent cap is the consideration that at the OAG's recommended 15 percent cap the incentive rises much more slowly than one capped at 30 percent. This runs the unnecessary risk of defeating the purpose of the incentive, i.e. to motivate increased cost effective energy conservation expenditures. In addition, under the Plan's incentive structure, each utility must achieve savings that significantly surpass the energy-savings that can be achieved at minimum statutory spending levels before receiving a substantial incentive. And even at the capped level, the utility's share of net ratepayer benefit is comparatively small. To illustrate, at a maximum performance and the 30 percent incentive cap, NSP would be rewarded only 8.25 percent of the total financial benefit to ratepayers due to the company's conservation expenditures. Indeed, the importance of capping the incentive at all recedes in relative importance since the incentive always remains a small portion of ratepayer benefit.

C. Review of Avoided Cost Calculations

The OAG noted that the Plan provides for incentives to be awarded based, in critical part, on the utilities' estimates of the benefits (principally avoided costs) due to its conservation expenditures.

OAG suggested that the Commission disallow recovery of the additional expenses incurred by the utility due to its failure to comply with the Commissioner's Order if it finds these expenditures to be imprudent. The OAG reasoned as follows: if a utility does not meet the DSM energy savings ordered by the Commissioner it must have purchased or produced energy to replace the energy that was not conserved. Since the Commissioner has already found that achieving these energy savings would be less expensive than producing or purchasing the equivalent amount of energy, the OAG argued that these energy costs should be viewed, *prima facie*, as imprudently incurred and, hence, denied if the utility cannot prove to the Commission that they were indeed prudently incurred.

The Commission notes that the Commissioner of Commerce has not requested assistance in enforcing his orders and the Department does not support the OAG's suggestion that the Commission should do so in this manner. The issue directly at hand in this docket is the CIP incentive, not compliance with Department CIP Orders. Further, the Commission has found in this Order that the appropriate baseline goal for the utility is the Incentive Energy Savings Goal which, while distinct from the Commissioner's savings and energy mandates, is closely related to those mandates and may provide appropriate incidental reenforcement and motivation for utilities to comply with Commissioner's orders. Finally, the Commission notes that a utility does experience a substantial consequence for failure to meet (and surpass) the Incentive Energy Savings Goal, i.e. the utility loses out on receiving the progressively substantial incentives established in the Plan.

Taking these factors into consideration, the Commission will not adopt the OAG's recommendation.

III. NSP'S LOAD MANAGEMENT DISCOUNT PROPOSAL

NSP-Electric refers to the difference between the rate for firm service and the rate for interruptible service as its load management "discount" and has requested that it be allowed to recover a portion of that discount.

NSP currently offers lower ("discounted") rates to customers who will agree to have their electric service interrupted during periods of peak usage. Customers agreeing to interruptible service help the Company manage its load. In return for subscribing to interruptible service, interruptible (load management) customers receive a discounted rate. The discounted rates given customers for interruptible service were established in recognition of the costs that NSP avoided by not having to invest in additional capacity to serve those customers. The discounted rates for interruptible customers recover all the costs of providing the interruptible/non-firm service.

NSP offered four reasons why the Commission should allow recovery of its load management discounts.

First, the Company stated that load management discounts are actually CIP costs that should be allowed as such. The Commission disagrees. Load management discounts are not CIP costs. The Commission correctly analyzed this issue in its February 18, 2000 Order in Docket No. E-

002/M-99-419. On page 6 of that Order, the Commission stated:

> Load management discounts are not CIP costs. . . . The Company acknowledged that it has treated load management discounts as an incentive and has traditionally sought to recover them in the CIP adjustment charge as a CIP incentive. The Commission finds no merit in the claim that these discounts are actually costs. The Commission notes that the load management discounts are quite unlike program costs in that they are not out-of-pocket costs or investments made in administering CIP programs. Rather, they are more like lost margins in that they are amounts foregone (not realized) as part of the CIP program.

Second, NSP argued that load management is one of the most effective actions a utility can undertake for ratepayers. In considering proposed financial incentives, however, the Commission must consider not simply the effectiveness of a measure, but whether a financial incentive must be given the utility to induce it to promote (or not interfere with) the measure. If no incentive need be given to induce the Company to act (or refrain from acting) in a certain way, awarding a financial incentive to the utility would be obligating ratepayers in return for nothing that would not have occurred anyway, i.e. in return for nothing.

Third, NSP asserted that an incentive (such as recovery of a portion of the load management discounts given to interruptible/load management customers) is required to motivate the Company to promote load management discounts. The Company stated that unless it is allowed to recover at least a portion of the load management discounts it will have an incentive (self-interest) to move interruptible customers to firm service which, the Company notes, generates significant higher margins. In short, NSP argued, recovery of a portion of the load management discounts is necessary to counter the Company's natural motivation (self-interest) to discourage interruptible (load management) service and move interruptible customers to firm service.

The Commission finds that the record does not support NSP's argument. As an initial observation, although NSP may receive additional revenues if a customer subscribes to firm service, it also incurs additional costs to serve that customer. In fact, as noted above, the load management discount itself was calculated to be the equivalent of the costs that NSP avoided by not having to invest in additional capacity to serve firm customers.

More importantly, times have changed from when it was in NSP's self-interest to construct supply side resources to increase the rate base upon which it could receive a rate of return on its investment. With the prospect of competition and possible resulting stranded investment, utilities such as NSP have increasingly been using contracts to purchase additional supply to meet the needs of its firm customers. Since NSP does not earn a return on these purchases, the Company has no incentive to increase the need for such purchases by switching interruptible customers to firm service, as the Company suggested it might do if not allowed to recover a portion of its load management discounts.

its (firm) customers, NSP would naturally like to avoid having to purchase additional (higher priced, peak) supply to meet firm customers' demand since the cost of such higher priced energy would be automatically transferred to its firm customers through the fuel adjustment clause. Similarly, in light of potential competition, the Company will be disinclined to (or unable to) motivate customers to switch to higher priced firm service from interruptible, since interruptible rates have proven popular with many customers as a way to reduce their energy costs.

In current circumstances, it is no longer in NSP's self-interest to build new supply side resources and to discourage the growth of interruptible service. The Commission finds that NSP has adequate self-interest to expand interruptible service without receiving an added incentive of half the discount it gives customers for agreeing to interruptible service.

Fourth, NSP argued that since load management discounts complement its CIP load management programs and work together to the benefit of ratepayers, it should be allowed to recover a portion of the load management discount as long as load management is approved as a CIP program.

The Commission finds no persuasiveness in this argument. Assuming that these discounts and programs are complementary, their complementary nature would not justify granting NSP the requested financial incentive, because to do so would give the Company money for something it already has adequate reason (motivation) to do.

To conclude, when evaluated in the context of the four considerations listed in Minn. Stat. § 216B.16, Subd. 6c, NSP's request to recover a portion of its load management discounts must be rejected because it fails on all four counts. Giving NSP money to motivate it to do what it already has adequate motivation to do is 1) not likely to increase utility investment in cost-effective energy conservation; 2) not compatible with the interest of utility ratepayers and other interested parties; 3) not linked with NSP's performance in achieving cost-effective conservation; and 4) in conflict with the just and reasonable rates requirement of Minn. Stat. § 216B.03.

IV. COMMISSION ACTION

A. Commission Action Regarding the Proponents' Incentive Plan and the Utilities' Individual Incentive Plans

A complication the Commission encounters in implementing the Energy Conservation Statute (Minn. Stat; § 216B.241) is that while the statute's principal goal is to promote **energy conservation (kWh savings)** that will result in ratepayer and societal benefit, the statute itself does not establish specific energy **savings** requirements, but instead mandates a certain level of conservation program **expenditures**, calculating the utility's required expenditure level as a percentage of the utility's gross operating revenue. Minn. Stat. § 216B.241, subd. 2b.

Although the statute mandates that CIP programs must be cost-effective to receive Department approval, the Commission has been left to its own devices to administer the statute in a manner likely to achieve the statute's ultimate goal (societal and ratepayer benefit due to energy conservation savings) and has endeavored to do so in light of its additional statutory duty to assure that rates (amounts recovered from ratepayers for gas and electric utility service) are just energy industry is undergoing changes with respect to diversity and competition.

Realizing these complexities, the Commission recognizes and particularly appreciates the extensive work sessions devoted to CIP incentive issues by all the parties to this proceeding. Unanimity was not reached in all aspects of the incentive considered in this docket, as the above discussions indicate. However, the CIP incentive clearly received a thorough reevaluation by the parties in these sessions and a remarkable level of clarity was achieved. The parties' work provided an important framework for the Commission's consideration of the relevant issues in the current Order.

Based on its review of the Joint Proposal, the parties' oral and written comments, and the Commission's foregoing findings and analysis, the Commission concludes that the Proponents' Plan is a reasonable approach to achieve the requirements and purposes of the Energy Conservation Statute (Minn. Stat; § 216B.241), taking into consideration the factors listed in Minn. Stat. § 216B.16, Subd. 6c and the Commission's duty under Minn. Stat. § 216B.03 to assure just and reasonable rates.

Specifically, the Commission has reflected upon the four considerations listed in Minn. Stat. § 216B.16, subd. 6c. Based on its review of the Proponents' incentive Plan and individual utility incentive plans and the objections and/or modifications articulated by the Large Customers and the OAG, the Commission finds as follows.

(1) The Proponents' incentive Plan and individual utility incentive plans based on that Plan, as modified by the Department's revised filings December 6, 1999, are likely to increase utility investment in cost-effective energy conservation. The incentive grows for each incremental block of energy savings. The incentive for achieving each new increment of energy savings increases as the percent of goal achieved increases. No significant incentive is provided unless a utility meets or exceeds the utility's expected energy savings at minimum statutory spending guidelines. The increasing increments of the incentive motivate utilities to exceed savings achievable at statutory spending levels.

(2) The Plan and the utilities' plans are compatible with the interest of utility ratepayers and other

therein) and the individual utilities' November 8, 1999 filings, as modified by the Department on December 6, 1999. The Plan and the spreadsheets filed by each utility on November 8, 1999 and modified by the Department on December 6, 1999 together constitute the utilities' individual incentive plans for 1999 and beyond. The Commission clarifies that its approval does not extend to the proposal by NSP to recover a portion of its load management discounts, which is specifically addressed and rejected elsewhere in this Order.

B. Commission Action Regarding NSP's Load Management Discount Proposal

Based on its review of the record, the parties' oral and written comments, and the Commission's analysis and findings on this issue in this Order, the Commission will reject NSP's load management discount proposal.

ORDER

1. The Joint Proposal for a Shared-Savings DSM Financial Incentive Plan is approved as filed.

2. Commission approval of the Joint Proposal includes:

    a. approval of the proposed Shared-Savings DSM Financial Incentive Plan's method for calculating incentive energy savings goal;

    b. approval of incentive trigger at 91 percent of incentive energy savings goal;

    c. approval of the percentage of net benefits awarded (Row D in the spreadsheets) for 1999 for electric utilities, and for 1999 and 2000 for natural gas utilities; and

    d. approval that the incentive amount is equal to net benefits (Row C in the spreadsheets) multiplied by the percentage of net benefits awarded (Row D in the spreadsheets).

3. The spreadsheets filed by each utility on November 8, 1999 and modified by the Department on December 6, 1999 (which, together with the Plan, constitute the utilities' individual incentive plans for 1999 and beyond) are approved. Dockets and companies affected by this decision are:

    G-004/M-99-535 (Great Plains Natural Gas Company);
    E-001/M-99-537 (Interstate Power/Alliant);
    E-015/M-99-538 (Minnesota Power);
    G-007/M-99-549 (Northern Minnesota Utilities);
    E-002/M-99-508 (Northern States Power Company-Electric);
    G-002/M-99-550 (Northern States Power Company-Gas);
    E-017/M-99-510 (Otter Tail Power Company);
    G-011/M-99-548 (Peoples Natural Gas Company); and
    G-008/M-99-509 (Reliant Energy Minnegasco).

4. NSP's request to continue recovery of a portion of the load management discount is denied.

5. This Order shall become effective immediately.

BY ORDER OF THE COMMISSION

Burl W. Haar
Executive Secretary

(S E A L)

This document can be made available in alternative formats (i.e., large print or audio tape) by calling (651) 297-4596 (voice), (651) 297-1200 (TTY), or 1-800-627-3529 (TTY relay service).

STATE OF CONNECTICUT

DEPARTMENT OF PUBLIC UTILITY CONTROL
TEN FRANKLIN SQUARE
NEW BRITAIN, CT 06051

DOCKET NO. 03-11-01 DPUC REVIEW OF CL&P AND UI CONSERVATION AND LOAD MANAGEMENT PLAN FOR YEAR 2004 – PHASE II

July 1, 2004

By the following Commissioners:

John W. Betkoski, III
Donald W. Downes
Jack R. Goldberg

DRAFT DECISION

This draft Decision is being distributed to the parties in this proceeding for comment. The proposed Decision is not a final Decision of the Department. The Department will consider the parties' arguments and exceptions before reaching a final Decision. The final Decision may differ from the proposed Decision. Therefore, this draft Decision does not establish any precedent and does not necessarily represent the Department's final conclusion.

DRAFT DECISION

I

I. INTRODUCTION

A. SUMMARY

In this Decision the Department approves the Companies' proposed 2004 budgets and programs and approves $1,210,580 in costs related to the severance of CL&P C&LM employees. The Department will issue an RFP to conduct an audit of the CL&M programs. The Department evaluates the major findings of the Office of Consumer Counsel report, Review of Connecticut's Conservation and Load Management Administrator Performance, Plans and Incentives. Based on this evaluation, the Department directs the Companies to make modifications in their performance incentive mechanism, the process of setting program goals and conducting program evaluations, and joint program delivery. The Department will not authorize supplemental

> The intent of this budget in January was to advise the EMCB and the Department of the amount, general amount of carryover funds that we saw that were coming available in 2004, and our expectation at that time would be that the securitization bond issues would have occurred around that timetable . . . . one of the reasons that we submitted this budget at this time was to try to keep this process as seamless as it can be. So when securitization is done, the $4 million a month cap is no longer holding us back, that we don't - we eliminate any other barriers to preventing us from starting and stop - or requiring us to start and stop programs. So we wanted to have this budget approved also as a backup, realizing that we're going to get into more detail on an 18-month or two-year budget cycle for this, but to at least approve in principle – this is somewhat of a rolling budget - so when we get into later this year and funds are - programs are going like hot cakes, that we don't slow down and shut down programs, that we have an option to spend some of these dollars in programs that are really taking off, using this same type of parity that we've developed here. Tr. 4/26/04, pp. 784-786.

The Companies also indicate that they would prefer to revisit the budget with the ECMB once the RRBs are issued and submit a more detailed budget, one that is more exact than the April Budget. Tr. 4/26/04, p. 788. The Department has included the April Budget as Appendix 2 and has revised the layout to show the subtotal for major categories below each group of costs. The Department notes that Appendix 2 compares the combined budgets for each program.

The April Budget reflects an increase of approximately 80% above the original 2004 budget, reflecting an allocation of carryover funds to a variety of programs. In general, the Companies seek approval of increased spending within approved programs to allow programs to operate uninterrupted and to avoid ongoing requests for Department review/approval of program spending.

The Department's goal is to allow C&LM programs to operate continuously and without the need for constant intervention. Further, as stated in past C&LM Decisions, the Department seeks to provide the Companies with the flexibility necessary to shift program dollars as necessary to react to market conditions or new program initiatives, in order to achieve savings cost-effectively. Therefore, the Department agrees that the Companies should be allowed to assign unallocated funds within approved programs.

Year 2003 was tumultuous for customers, vendors and program administrators because C&LM programs were effectively halted. In light of the proposed increases for 2004, the Department is concerned that by significantly increasing spending for the remainder of the current period programs may experience a 'roller-coaster' effect through 2005. The Department seeks to avoid such patterns and directs the Companies to take steps to that effect. The Department therefore anticipates that there will be carryover funds available for 2005.

The budget reflects $6 million that the Companies had set aside for RRB issuance costs. In a letter dated June 18, 2004, submitted in Docket No. 03-09-08, Application of The Connecticut Light and Power Company and The United Illuminating Company for a Financing Order, the Office of the Treasurer submitted an Issuance

Advice Letter to the Department. The Issuance Advice Letter contains a summary of the results of the bond issuance that was required to allow the C&LM programs to continue to operate. The Issuance Advice Letter states that the cost of issuance was funded through issuance proceeds. Therefore, the $6 million set-aside is available for C&LM programs and must be allocated.

In addition, the April Budget does not indicate the increased expenditures for the Appliance Retirement programs approved in the February 4, 2004, Decision in this proceeding. Therefore, the budget must be amended to reflect the approved budget for these initiatives. Further, the Department is concerned with the increases that are budgeted for Administrative & Planning items, notably Planning & Evaluation, Information Technology, ECMB and Audit costs.

Based on the foregoing, the Department will allow the Companies to allocate carryover funds as proposed but will require the Companies to submit final revisions to the April Budget to reflect the items noted above and to explain the need for the increases within the Administrative categories. The Companies shall use the layout in Appendix 2 but shall show each Company's program budget as submitted in the April Budget.

B. OCC CONSULTANT REPORT

1. Introduction and Summary

As indicated in the Notice of Hearing dated November 20, 2003, the Department is considering in Phase 2 of this docket the OCC Report. The OCC, in response to the Department's decision in Docket No. 03-01-01, engaged Optimal Energy, Inc. (Optimal), Vermont Energy Investment Corporation (VEIC) and PAH Associates (Collectively, OCC Consultant) to examine the past and planned performance of the current program administrators (PA) in achieving C&LM policy objectives under the current performance incentive mechanism and to recommend changes as appropriate. The OCC Report provides an independent response to the DPUC request for the ECMB and the Companies to "review, re-assess and revise performance incentives" for administrators of Connecticut's C&LM investment portfolio. DPUC Decision in Docket 03-01-01, May 28, 2003, p. 1. The OCC Consultant reviewed a variety of materials, including past Department C&LM decisions, the 2004 C&LM Plan, program evaluations other relevant documents, as well as conducting interviews with C&LM contractors and vendors.

The OCC Report compares past and planned performance of Connecticut's C&LM programs in key residential and commercial markets with that of programs in Massachusetts, New Jersey, New York and Vermont. The OCC Report concludes that while information among the statewide comparison is somewhat uneven, Connecticut utilities have performed favorably, based on several objective measurements, such as expenditures per kilowatt-hour (kWh) saved and energy savings as a share of retail sector sales. However, in some cases, such as residential new construction, Connecticut's program administrators have not succeeded as well as their counterparts in nearby states. The OCC Consultant suggested that they would give Connecticut C&LM administrators, "overall, an A minus on their work, at the overall electricity savings level" and "would award a B plus/A minus in the residential end and an A minus in the commercial/industrial end." Tr. 4/12/04 p. 504.

The OCC Report recommends a program budget allocation that it believes would yield the greatest electricity savings and economic value from the $100 million available to fund Connecticut's C&LM investment portfolio for 2004 and 2005, consistent with the Report's recommended policy priorities. The OCC Report recommends a reprioritization of several budget items, specifically, substantial increases in Residential Heating and Cooling, Residential Audits/Loans, Commercial New Construction, and commercial and industrial (C&I) Retrofit/Energy Opportunities. OCC Report, p. 11. The OCC Consultant recommends substantial cuts or total elimination in several program areas.[1]

Cross-program recommendations include joint delivery of uniform program designs statewide and implementation of a regular savings verification process. In the residential sector, the OCC Consultant recommends greater coordination with other state and regional new construction initiatives, and refined eligibility requirements and redesigned incentives for the heating, ventilating and air-conditioning (HVAC) program. In the C&I sector, the OCC Consultant recommends elevated minimum lighting efficiency requirements and consolidation of the multiple programs serving overlapping markets. The Reports also proposes key modifications of program goals and the performance incentive mechanism. Id., pp. 9-10; pp. 57-69.

The OCC Consultant concludes that the primary objective of Connecticut's C&LM investment portfolio should be to maximize the yield of both electricity savings and economic value, consistent with direction in the Department's latest decision. The OCC Report recommends that the DPUC recognize total net resource benefits, not just electric benefits, as the true indicator of economic efficiency and thus gains to Connecticut's economy. The OCC Report recommends the systematic incorporation of non-electric savings into planning and program design, which maximizes overall economic benefits to Connecticut ratepayers. Non-electric savings should be incorporated as a marketing and decision-making tool to maximize overall energy savings; however, programs must be determined to be cost-effective using the electric test. Id., pp. 14-17; Tr. 4/12/04, p. 505, 514 and 520.

2. Total Resource Test

The OCC Consultant believes that the Department should adopt the Total Resource Test (TRT) as the primary test for determining whether a C&LM program should receive regulatory support. The OCC Consultant recommends that the Electric System test should be used as the secondary test, providing a measure of ratepayer equity. The OCC Consultant also recommends that the Department should continue to use the Electric System Test to address equity issues regarding funding of nonelectric saving measures or projects. The OCC Consultant urges the Department to require that C&LM programs provide a cost-effective level of electric cost savings to each major customer sector, and to encourage them to maximize the net economic value from all major types of resource savings from C&LM investments: electricity, natural gas, oil,

[1] Substantial cuts are recommended for SmartLiving Centers and the Community Based program. OCC Consultant recommend elimination of Refrigerator Retirement, SmartLiving Catalog, Heat Pump Water Hear, Residential RFP, Residential Renewables, O&M RFP/O&M Services, State Buildings, Municipal program, C&I RFP, and the Load Management. OCC Report, p. 11.

and water. Id. p. 16; Tr. [redacted]

3. Performance Mechanism and Incentives

(a) OCC Performance Incentive Mechanism

The OCC Consultant states that the purpose of a performance incentive is to encourage the best possible achievements by portfolio administrators in the pursuit of Connecticut's C&LM policy objectives. This goal should apply to the incentive awards for individual program performance as well as collectively to the total incentive award. The OCC Consultant states further that an effective incentive mechanism should produce performance indicators that are observable, measurable, verifiable, clearly aligned with policy objectives, and that do not create perverse incentives for administrators to act in ways contrary to policy objectives. OCC Report, pp. 11-13.

For maximum effectiveness, the performance incentive mechanism should combine incentive awards for superior performance with penalties for failure to meet minimum performance requirements. In addition, the incentives should reward results above performance goals to encourage exceptionally strong performance, up to a maximum award. Conversely, administrators should be able to earn partial awards below performance goals so they will continue striving for success as long as the outcome falls above specified minimum thresholds. Minimum performance requirements also reinforce performance incentives by reducing the incentive award for failure to meet minimum standards for administrator performance in other critical areas. Id.

According to the OCC Consultant, the current incentive mechanism should be changed in order to motivate the best possible performance from CL&P and UI. The OCC Consultant finds that current goals do not represent a "stretch" from the previous years' accomplishments. Further, the OCC Consultant states that under the current design, the performance incentive may be draining too many resources from the limited funds available for program expenditures. Id.

The OCC Consultant finds that the current mechanism does not align with State policy objectives and has piecemeal incentives that unduly reward individual outcomes. As previously stated, the OCC Consultant recommends that the performance incentive include total net resource benefits as the true indicator of economic efficiency and thus gains to Connecticut's economy. The OCC Consultant also finds that the shortcomings in the performance mechanism have resulted in a tendency toward micro-management of the fund administrators by the Department. The OCC Consultant concludes that a redesigned performance incentive mechanism will address these problems. Specifically, the OCC Consultant recommends the following:

1. that a revamped performance mechanism be designed to encourage maximum economic and electricity yield from the portfolio, particularly where savings are needed most to avert reliability problems in southwestern Connecticut;
2. that the mechanism apply to CL&P and UI together, so that their individual rewards depend on how well they perform jointly in their shared tasks;
3. that the mechanism and goals apply over at least a two year period to allow administrators greater flexibility;

4. that the Department set aside $4.5 million for potential performance awards for superior management of the $100 million two-year investment portfolio;
5. that individual performance incentives be established so that administrators can earn extra incentives for exceptionally strong performance on individual goals, or conversely, earn partial incentives for performance below an established goal but above a minimum threshold. Id., p. 10.

The Department discusses these recommendations below.

(b) Potential Incentive Dollars

Under the current design, the OCC Consultant concludes that at its upper end of 8%, the performance incentive could drain too many resources from the limited funds available for program expenditures. OCC Report, p. 4. The OCC Consultant recommends decreasing the total potential performance incentive from the level that is currently available to the Companies. Based on its experience, the OCC Consultant recommends a performance incentive of approximately four and one half percent of the total budget. The OCC Consultant states that its recommended performance level is based on its assessment of the difficulty of the task of operating C&LM programs as well as the risk/reward available to the Companies in running these programs. In support of its position, the OCC Consultant states that the ratepayers provide all the funds used for C&LM activities and as a result, there is little or no risk to the program administrators since all costs are fully reimbursed. Tr. 4/12/04, pp. 595-597.

CL&P maintains that the potential performance incentive recommended by the OCC Consultant is lower than that which is currently available and would be spread over two years. CL&P believes that the incentive should be maintained at its current level and that the incentive should be reconciled annually. Id. Tr. 4/26/04, p. 728.

UI states that the Companies execute their conservation programs with "a creative entrepreneurial spirit" and in so doing achieve significant savings. UI states further that:

> if we weren't a regulated company and we were doing this as an entrepreneurial business, we would be hard-pressed to entertain somebody to . . . provide that kind of service with that kind of performance (energy savings) with a margin as small as that (provided in the current structure). Tr. 4/26/04, pp. 727-729.

UI maintains that its current incentive mechanism has produced excellent results and therefore it urges the Department to maintain the current structure. UI Brief, p. 1.

The structure of the current incentive mechanism is straightforward; the Companies set a goal and if they meet or exceed it, they earn a performance incentive payment based on a percentage of program expenditures. The following table shows the performance percentage and the pretax incentive available under the current Performance Incentive. As the table shows, at present the Companies can earn a maximum of eight percent of their C&LM expenditures if they exceed the goals for these programs by 30%.

Performance Incentive	Pretax Incentive
70-80	2%
80-90	3%
90-99	4%
100-109	5%
110-119	6%
120-129	7%
130 and above	8%

Source of Data:
Decision dated May 28, 2003
In Docket No. 03-01-01, p.12.

As established by Conn. Gen. Stat. 16-245m, the C&LM fund provides the Companies with a guaranteed multi-million dollar revenue stream that is dedicated to the administration of C&LM programs. These revenues cover all costs associated with these programs. An example of the limited risk associated with the fund is evidenced by § 16-245m(a). This statute was enacted to provide the Companies with the assurance that their C&LM expenditures would be recovered through the Competitive Transition Assessment while the issue of Legislative action regarding the fund was pending in 2003. Another example regarding risk is discussed in this Decision. During 2003 CL&P needed to reduce its C&LM staffing levels as a result of the then pending reductions to C&LM funding. The C&LM fund absorbed all costs associated with CL&P's personnel reductions, holding CL&P harmless for these costs. Further, C&LM programs are designed to provide direct customer benefits through reduced energy costs. In many cases the total incremental cost of the efficient measure is borne by the fund. The C&LM fund allows the Companies to market these programs to their customers as utility-sponsored initiatives at ratepayer expense. Therefore, in addition to the no-risk nature of operating the programs, the Companies enjoy the benefit of improving customer goodwill through the marketing budget for these programs, at no cost to the utility.

The Department has considered the issues raised by the OCC Consultant regarding the risk/reward that accompanies the C&LM fund. The Department concludes that there is little or no risk to the revenues from the Companies' regulated activities associated with the operation of C&LM programs and that the Companies benefit from the operation of these programs. While this may appear to support a reduction to the potential incentive, in light of the 'report card' that the Companies have achieved regarding their C&LM performance, this course of action is unwarranted. The Department cannot overlook the fact that the C&LM programs have received national recognition and have achieved significant savings. It would be inappropriate to 'reward' the Companies for past performance by reducing the potential level of the incentive. The Department finds that current incentive structure has proven successful in motivating the Companies to achieve savings. As a result, the Department will maintain the maximum potential incentive at the current level of 8%. The maximum potential will be based on the overall budget, but will not based on program expenditures. However, as discussed below, the process for setting goals and targets must be addressed.

(c) Joint Delivery

The OCC Consultant affirms that Connecticut's C&LM program designs are among the best in North America. However, the OCC Consultant believes that there are opportunities for improving the current approach to C&LM marketing and business development because the current programs do not share consistent statewide designs and lack transparency in the markets they seek to influence. The OCC Consultant states further that consistent statewide design would improve portfolio performance by deploying program services (financial, marketing, delivery) according to the organization and operation of efficiency markets. Because utility boundaries are irrelevant to new construction, appliance purchases, and equipment replacement markets, any geographic variation in program design within a particular market will introduce a potential barrier to participation. Since overcoming and eradicating market barriers is the very purpose of C&LM program investment, it follows that administrators of Connecticut's C&LM program should immediately move to standardize all programs aimed at statewide markets. The Consultant notes that although a limited number of programs may require geographic variation in program designs (e.g., targeted investment in SWCT) such programs should be carefully packaged as "bonuses" that appeal to all market participants. Ultimately, greater statewide consistency should enable administrators to raise electricity savings and economic value by increasing market participation and by reducing administrative costs. OCC Report, pp. 50-52.

The OCC Consultant asserts that strengthening the market orientation and customer focus of various program services should improve effectiveness and lower costs. Marketing efforts should be consolidated and better coordinated among programs to improve overall cohesion of services within statewide markets and between related markets (e.g., equipment replacement vs. new construction). Ideally, the programs themselves should be invisible to customers and other market participants. Id.

The OCC Consultant indicates that they interviewed market actors, and that some of those interviewed stated:

> "the multiplicity of programs unduly complicated and confused customers and trade allies, particularly in the C&I sector. Some of those interviewed commented that program procedures drive up their own administrative costs to participate in C&I programs. Such higher costs create barriers to participation, which defeats the very purpose of C&LM programs. OCC Report, p. 51.

The OCC Consultant also states that the Companies could also increase the electricity and economic yield from the C&LM portfolio if they can find ways to leverage the resources of other market participants. Administrators need motivation to take maximum advantage of opportunities to cooperate with regional and national market transformation efforts, including Northeast Energy Efficiency Partnerships (NEEP) and the EPA Energy Star® label. The OCC Consultant believes that these objectives are better achieved through a joint performance mechanism. OCC Report, p. 51.

The OCC Consultant states that while UI and CL&P have been directed to operate their C&LM programs jointly, each Company's performance incentive is based on their individual performance. The Consultant states that UI and CL&P should be held jointly responsible for the performance of C&LM programs and that this standard is a critical element of the proposed Performance Incentive Mechanism. OCC Report, p. 51; Tr. 4/12/04, p. 602.

The Companies indicate that they are continuing to look at ways to deliver their programs jointly and as an example are working toward a single toll free number that customers can use to access all C&LM-related information. The Companies maintain, pursuant to the Department's directives, they have made significant strides toward the joint operation of C&LM programs. However, the Companies continue to believe that there is value in having different approaches to program design and implementation. The Companies also state that there may be a tendency to overvalue the single entity concept. Further, the Companies maintain that there is value in maintaining separate corporate identities for some programs because the customers served by each utility have unique needs. Tr. 4/26/04, pp. 709, 772-781.

In 1998, the Department required UI to participate in a joint conservation program with CL&P, the SmartLiving Catalog, citing the benefits of a combined effort. See Decision dated April 8, 1998, in Docket No. 97-10-01, DPUC Review of The United Illuminating Company's 1998 Conservation and Load Management Program and Budget, pp. 6-10. In 1999, the Department approved the continuation of UI's participation in the SmartLiving catalog program. See Decision dated June 30, 1999, in Docket No. 98-10-05, DPUC Review of The United Illuminating Company's 1999 Conservation and Load Management Programs, p. 4; Decision dated June 30, 1999, in Docket No. 98-11-02, DPUC Review of The Connecticut Light and Power Company's 1999 Conservation and Load Management Programs, p. 10. In 2000, the Department continued the movement toward joint C&LM initiatives. See Decision dated May 10, 2000, in Docket No. 99-09-30, DPUC Review of the Connecticut Light and Power Company's Conservation and Load Management Programs for 2000, Decision, pp. 4-6. In that Decision the Department stated:

> Over the past few years the approach to implementing conservation has shifted from stand-alone, utility-by-utility initiatives, to coordinated regional and national ones. As a result of this trend the Department believes it is appropriate to increase the number of joint programs at this time. However, all in-state programs should be identical. In addition to the customer-related benefits noted above, identical programs would simplify review by the Board and the Department and would ease implementation by customers, contractors and energy service companies (ESCOs)... Based on the foregoing, the Department will require that CL&P develop identical residential and small commercial and industrial programs in conjunction with UI for 2001. Decision, p. 6.

Since 1999, the Department has required that CL&P and UI move toward the joint operation of C&LM programs. Since that time the Companies have created many joint initiatives, have consolidated separate C&LM filings into a single annual plan and have developed a joint cost/benefit analysis. Although the Companies operate many identical programs, the Companies continue to cling to the need to maintain separate identities for at least some of these programs.

In its Decision dated May 10, 2000, in Docket No. 99-03-30, p. 5, the Department discussed CL&P's concerns as they relate to the creation of joint C&LM marketing materials and campaigns. Despite CL&P's concerns, in keeping with the movement toward joint program operation, the Department directed CL&P to move toward additional joint marketing strategies. The Department stated that although achieving consensus on program promotion, content and incentives may require an increased effort initially, that the long-term benefits of a statewide approach to promoting energy efficiency will likely outweigh an additional upfront work and cost. The Department believes that the programs that have been operated and marketed jointly since that time have shown benefits to Connecticut's ratepayers and that the furtherance of the Department's policy of seamless program implementation is appropriate.

C&LM programs are tools for administrators. They provide rules for deploying services, and vehicles for tracking results in different markets. There is no valid reason to create and maintain distinct identities or brands for individual programs. Rather, customers should see a seamless web of services that fit naturally with, and overcome barriers to, the efficiency transactions they are involved with in the marketplace. Establishing separate identities for the individual programs in the marketplace introduces unnecessary confusion in the minds of consumers and other participants in efficiency transactions, including vendors, contractors, architects, engineers and other trade allies. Based on the foregoing, the Department will direct that the Companies move toward seamless operation of all programs and that all program activity be unified for the 2006 budget period.

Specifically, the Department believes that programs serving C&I customers should be marketed statewide under the same name for both Companies. This will create greater consistency between programs, as recommended by the OCC Consultant. Tr. 4/12/04, p. 553. This has already occurred for the Small Business Energy Advantage program. For the remaining C&I programs, UI has adopted a straightforward marketing approach by establishing "Energy Blueprint" (new construction) and "Energy Opportunities" (existing facilities) programs. The Department believes adoption of these program names statewide for both Companies would simplify marketing efforts, reduce customer confusion, facilitate the development of joint marketing materials, create the opportunity for more joint marketing efforts, and create a more seamless statewide approach to C&I program delivery.

In the case of CL&P's new construction program, the Company has recently changed its name from "Energy Conscious Construction" to "C&I New Construction" so there is no long-standing name recognition associated with this program. Id., p. 555. In directing CL&P to adopt Energy Opportunities as a program name, the Department is not advocating that CL&P eliminate C&LM services targeted to specific customer groups nor is it requiring CL&P to eliminate existing C&I programs. The identity of these separate programs should remain as "sub-programs" for the purposes of administration, program measurement, budget purposes and vendor relations; separate C&I sub-programs need not and should not be marketed to the customer. For example, a typical owner of a commercial facility may not understand the difference between the Custom Services and the Express Services programs; maintaining a separate identity does not provide the customer with meaningful information and may be confusing to the customer.[2] Id., pp. 553-555. Since CL&P will maintain its existing programs for administrative purposes, customers familiar with specific program names will still be directed to administrators and vendors associated with those programs. Both Companies would retain the opportunity to create joint marketing materials to C&I subgroups.

In the 2005 filing, CL&P will adopt "Energy Blueprint" (new construction) and "Energy Opportunities" (existing facilities) as C&I program names for marketing purposes. The Companies will discuss plans for developing joint marketing of C&I material and promotional activities.

In a separate but related issue, the Department directs the ECMB and CL&P to evaluate the benefits of consolidating the administration of some of the Company's C&I programs. There may be an administrative benefit to consolidating the Custom Services and Express Services programs as well as the C&I Operations and Maintenance (O&M) Services and O&M RFP programs. The Department will seek the advice of the ECMB and the Company on this matter.

Finally, the Department believes that one of the barriers to conservation is the customer's inability to access program information (technologies, rebates, product availability, etc) on a timely basis. To reduce this barrier the Department believes that customers need a single 'clearing house-type' phone number, where they can get answers to any conservation or energy-related question, or be directed to the appropriate resource for information. Therefore, the Department will direct the Companies to establish a single, statewide, toll free phone number that can be used by all customers to access information about all conservation programs and energy efficiency-related matters. The Department's intention for establishing this number is to provide customers with a "live body" during business hours, someone that can promptly direct inquiries about these matters. The toll free number must be operational by January 1, 2005.

(d) Modified/Joint Performance Mechanism

The OCC Consultant recommends that the performance mechanism apply to CL&P and UI together, so that their individual rewards depend on how well they perform jointly in their shared tasks. The OCC Consultant provided a proposed performance matrix. See Appendix 1 and OCC Report Tables 27, 32 and 35. The OCC Consultant states that a joint incentive mechanism will create additional efficiencies between the Companies as they strive for a common goal and believes that the proposed matrix will provide the Companies with the flexibility necessary to maximize the amount of incentive that the Companies can earn. Under the proposed performance matrix, the Companies would need to achieve activity milestones as well as energy and demand savings to earn incentive payments. Tr. 4/12/04, pp. 600-610; OCC Report, pp. 3-5, and 77-90.

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[2] "One individual indicated that, as a matter of course, he declines to participate in almost all C&I programs due to burdensome procedures. Another interview subject reported that understanding which program services they are eligible for was the single greatest source of customer anxiety." OCC Report, p. 51.

CL&P states that in many respects the incentive that has been proposed by the OCC Consultant is similar to the current mechanism. CL&P maintains that the major difference between the current and proposed models is that, in addition to the goals that are based on electric benefits, the OCC Consultant relies on the Total Resource Test to determine the success of the programs. CL&P also states that while the current incentive mechanism has operated well, it is open to looking at this issue going forward. Tr. 4/26/04, pp. 711 and 729.

UI states that it does not oppose the concept of a joint performance incentive. However, UI indicates that whatever incentive structure is chosen that it must avoid the opportunity for gaming and should not provide perverse incentives. As an example, UI cites the current incentive structure and the fact the incentive is calculated as a percentage of actual expenditures. Under this approach, the Companies achieve fewer incentive dollars when they reach a goal at less than the budgeted amount. This presents a perverse incentive and may result in unnecessary expenditures in order to provide a higher incentive payment. Tr. 4/26/04, p. 725. UI notes that while this has not occurred, and its programs are generally oversubscribed, that these types of opportunities should be eliminated. Tr. 4/26/04, pp. 725-727.

As noted by the Companies, the current incentive system provides a perverse incentive because the level of the incentive payment is tied to program expenditures. Although the Companies state that they have not manipulated the incentive in the past, the Department believes that the structure should be changed to avoid any potential for such gaming. The Department notes that it has expressed concern regarding the potential to game the incentive mechanism in the past. Docket No. 03-01-01, Decision dated May 28, 2003, <u>DPUC Review of The Connecticut Light and Power Company's and The United Illuminating Company's Conservation and Load Management Programs and Budgets for Year 2003 and 2004</u>, pp. 16-18. Therefore, based on the foregoing, the Department concludes that although the overall budget can provide a basis for establishing the total incentive, it is unreasonable to continue to calculate the performance incentive based on program spending.

The Department recognizes the excellence in the program delivery by the Companies under the current incentive structure. However, the Department believes that the OCC Report demonstrates the merits of fine tuning the incentive mechanism. Importantly, broadening the measures by which the Companies earn incentives would lessen the need for the Department to micromanage the Companies' operations and goals for specific programs. It would reduce the number of Department orders in decisions to obtain specific program goals and savings targets and allow the Companies greater flexibility in program administration. Including other program performance measures in addition to kWh saved in the incentive mechanism provides a more precise quantitative target for supplementary goals, such as targeting SWCT or including all fuel savings in low-income housing retrofits. Providing a multidimensional

The OCC Consultant has recommended a template for a performance matrix. OCC Report, pp. 80, 85 and 90. The Department has included the proposed matrix as Appendix 1. The Department believes that the use of a joint performance mechanism is appropriate and in keeping with the Department's policy of joint implementation of C&LM programs. Therefore, the Department will require that the Companies adopt this format and work together toward unified goals. The Department believes that performance incentives should emphasize total kWh savings, but agrees that cross-sector performance incentives that consider peak kW reduction in SWCT and TR benefits should also be included. The OCC Report provides a useful template for specific program performance indicators in the residential and C&I programs and milestone events in other areas. Id. Based on the foregoing, the Department will direct the ECMB to adopt the OCC Consultant's matrix as a guide to developing specific cross-sector performance incentives as well as the targets and milestone events within the residential and C&I programs. The final matrix should allow sufficient flexibility in program administration to allow the Companies to earn an incentive. The final matrix will be implemented for 2006.

The OCC Consultant recommends a two-year incentive structure. OCC Report, p. 16. CL&P testified in support of an annual incentive true up that provides greater program accountability and ease in accounting. Tr. 4/26/04, p. 729. The Department supports continuation of the annual incentive return, and annual filing and decision cycle as the most effective means to set goals, and measure and evaluate programs.

The Companies and the Department have worked hard over the last three years to create identical program delivery and develop standard filing requirements and greater explanatory text in annual filings. As directed herein, these efforts will culminate in 2006 with the joint operation of all programs and incentive structure. This should result in a streamlined program evaluation process and should minimize the time required to review annual C&LM filings.

Beginning in 2006, all C&LM funds will be pooled for the purpose of program administration and the Companies will work toward common goals to maximize their respective incentive earnings. Although the program dollars will be pooled, incentive dollars will be earned based on the ratio of the C&LM contribution made by each Company's ratepayers. As an example, assume that the Companies achieve 100% of a kWh goal and 90% of the savings are achieved in CL&P's service territory. CL&P is not entitled to 90% of the incentive. CL&P's incentive is based on that Company's contribution to the C&LM fund.

(e) Goals and Targets

The OCC Consultant expressed concern regarding the setting of goals and recommends changes to the performance mechanism to address these concerns. For instance, the OCC Consultant recommends that instead of setting goals at the program or sector level that they be established at the portfolio level in order to provide program administrators with greater flexibility in achieving them. The OCC Consultant maintains that it is important to do a significant amount of work on the front end of the process to assure that budgets and goals are aligned and to assure that goals are properly set. The OCC Consultant states:

> This is one of the reasons we worked so hard on the budget part of this report, to see where we recommend the money go, and that tells you what you have to work with, and usually it is a matter of assessing achievable market penetration with the program designs that you can use, knowing the costs you have and the kind of response you have gotten, and setting the goals at a stretch . . . you try and set a goal that is hard to reach, but not so hard that it is unattainable because . . . if the goal is seen as impossible to meet, then it defeats its purpose (and) will be ignored. So you want to pick something that is a stretch, and put a zone around it so that failing to meet exactly the goal isn't failure. Tr. 4/12/04, pp. 607-609.

The OCC Consultant recommends that the Companies should have input into consultants to lead a technical meeting for this purpose. Each year, prior to the filing of the annual C&LM plan, the Companies and the ECMB technical consultants shall conduct one or more technical meetings to provide a detailed explanation of how the annual goals for each program or matrix component were set.

In the Decision dated May 28, 2003, in Docket No. 03-01-01, the Department established standard filing requirements for the annual C&LM plans. Decision, pp. 10 and 11. As part of the standard filing requirements the Companies are required to describe the goals for each program and explain how each was established. In the 2004 filing, the Companies included this information. In light of the increased focus on goals, the Department anticipates that the standard filing requirement will provide a more comprehensive explanation of how each goal is set. The Companies should provide references to the Technical Reference Manual, monitoring and evaluation reports and other technical references, as appropriate. These references are described below.

The Department briefly explored the concept of targeting the average annual consumption or the peak demand for the residential class as a goal within the C&LM programs. The OCC Consultant commented that while this type of goal might prove problematic within the commercial and industrial classes that it can be an appropriate standard for measuring success among residential customers. The OCC Consultant views this metric as a long-term indicator of success and cautions that this should only measure electric savings. Tr. 4/12/04, p. 614.

The success of residential C&LM programs is measured through demand or energy savings or the success in transforming markets. While these efforts ultimately help to limit the growth in residential demand and consumption, there is little or no emphasis placed on targeting the average annual consumption or the ever-increasing peak demand for this class as a goal within the C&LM programs. The Department believes that this issue should be explored in greater detail and plans to do so during the proceeding that will consider the 2005 C&LM budget.

4. Tracking, Monitoring and Verification

The OCC Consultant argued forcefully for greater accountability and independence from the Companies in the process of tracking, monitoring, and verification of performance claims. The OCC Consultant made three key recommendations in this area. The recommendations are:

1. the Companies should develop and implement an independently accessible data tracking system for program results;
2. the Companies should develop a technical reference manual (TRM);
3. the Department should establish an annual process for systematic verification of the Companies' performance claims.

With regard to its first recommendation, the OCC Consultant maintains that an effective tracking system should record the magnitudes and costs of the electricity and other resources provided by C&LM activities. The OCC Consultant recommends that the State of Connecticut should have access and ultimate control over tracking system records and that a tracking system should be part of the Companies' standard filing requirements. The OCC Consultant indicated that it was not familiar with the Companies' tracking system, but suggested that the Efficiency Vermont tracking system, FasTrack, was an effective tool. OCC Report, pp. 52-53; Late Filed Exhibit No. 2, Efficiency Vermont Year 2003 Preliminary Annual Report and Annual Energy Savings Claim, April 1, 2004, Supplemental Workpapers.

The Department notes that the OCC Consultant did not do a comprehensive study of the Companies' tracking systems and relatively little hearing time was spent investigating this issue. The Department is aware that the Companies track their electric and non-electric savings, but do not submit them comprehensively as part of their annual filings. The record in this docket is inconclusive whether the Companies' tracking systems operate jointly, and whether they are effectively identical.

The Department will direct the ECMB to evaluate the Companies' tracking systems further to assure that the Companies are conducting a comprehensive tracking analysis, and whether they are operating a consistent, joint tracking methodology. The Department directs the ECMB to work with the Companies to develop comprehensive presentation of tracking data for each C&LM program as part of their annual filings, beginning in 2006, using the Efficiency Vermont Annual Report and Annual Energy Savings Claim as a template. Rather than using county data, the Companies should present their data geographically as SWCT and non-SWCT. The Department expects that the ECMB will recommend a process by which the tracking system will be developed and maintained to meet the OCC Consultant's standard in which the Department has ultimate control over tracking system records.

Secondly, the OCC Consultant recommends that the Companies develop a technical reference manual (TRM): a detailed, comprehensive documentation of all claimed resource costs and savings corresponding to individual C&LM technologies. Such a TRM would be updated as technology, baselines, and measured savings change over the years. All tracking entries of C&LM projects are ultimately traceable and cross-referenced to the TRM. This document has been developed and used by Efficiency Vermont, which administers the C&LM fund in that state. OCC Report, p. 53; Late Filed Exhibit No. 2, Efficiency Vermont Technical Reference Manual, User's Manual, December 31, 2002.

CL&P testified that the Companies have worked together over the past several years to develop common assumptions regarding measured savings for all types of energy efficiency devices and projects; however, these technical assumptions are not compiled in a TRM. CL&P and UI indicated that they could compile these technical assumptions into a joint manual similar to the Vermont TRM. Tr. 4/26/04, pp. 770-771. The Companies' testimony suggests that the work involved in developing a TRM would be compiling and organizing technical data that is already on hand, rather than the additional work of data collection and technical research. Id.

The Department believes that the development of a TRM would provide value to the oversight process by providing an empirical link to the goal-setting and verification processes. The Department will require the Companies to develop a joint TRM, to be submitted in the 2006 filing. The Companies shall use the Efficiency Vermont model as the template for organizing the document.

Thirdly, the OCC Consultant expressed concern about the lack of independence in the verification process, and recommends that the Companies "should not be permitted a role in the decision-making process because of their obvious conflict of interest." OCC Report, p. 53. The OCC Consultant lauded the decision by the Department to initiate an independent financial audit of the C&LM activities. The OCC Consultant further recommends the establishment of a regular process for verifying the savings that are claimed by the Companies. The OCC Consultant believes that an annually submitted standard tracking system and the TRM will be instrumental in facilitating the verification process.

Over the past 12 years, the Companies have performed more than 180 evaluations. As part of their verification process, the Companies select third party consultants to conduct program evaluations to monitor program results. These evaluations include impact, process and baseline evaluations and market assessments. The Companies have budgeted approximately $1.5 million for third party planning and evaluation in 2004. These evaluations include five joint CL&P/UI evaluations, three CL&P evaluations, and three regional evaluations. C&LM 2004 Plan, Table A-1, p. 9; pp. 282-284.

The Department recognizes the comprehensiveness and the due diligence of the Companies to obtain third party program evaluations and to modify programs on the basis of the reports' findings and recommendations. However, we would like to see greater independence in the RFP selection process of third party evaluators.[3] The Department will direct the ECMB to develop a process that assures complete independence from the Companies in the selection of third party evaluators and the content of the evaluation reports. This should include an RFP selection committee comprised of ECMB/Department staff, selection committee receipt and review of draft reports, and any other recommendations that will assure complete independence from the Companies. Second, the Companies are directed to send evaluation reports to the Department upon their completion. The Department also believes there is value to reporting the major findings to the ECMB as the reports are completed. Third, the Companies shall integrate and reference the evaluation results into the annual goal-setting, annual tracking documentation, and TRM, as appropriate. Overall, the Department would like to see greater transparency and integration of the third party program evaluations into the ECMB oversight process as the ECMB and the Companies look toward the submittal of the 2006 filing. The Department welcomes additional suggestions from the ECMB to achieve this objective.

The Department believes that the submittal of detailed tracking data and a TRM, along with the recommended process changes to third party evaluations will make the goal-setting process more transparent and provide a seamless database of goal-setting, actual savings and program achievements. The Department is hopeful that, given the comprehensive nature of the data collection and evaluation work that are already part of the practices of the Companies, this effort will involve integrating and clarifying existing practices.

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[3] CL&P makes reference to the ECMB consultant providing oversight in the RFP selection process for a particular evaluation report. Tr. 4/26/04, p. 764. The 2004 Annual C&LM Plan, p. 282, states that, "The Companies plan to work with the ECMB consultants to identify specific areas for evaluation," but does not indicate that the ECMB or its consultant participated in the RFP selection process.

C. General Awareness Regarding the Conservation Fund

Recent actions by the Legislature placed the C&LM programs at risk of being shut down. Despite the potential to eliminate these programs, there was limited movement among the general public to maintain the fund or the programs it supports. The Department believes that this was due in part to the fact that many customers are unaware of the conservation fund and its value to the state. The Department also believes that customers may not connect the Conservation Fund to the many separate C&LM programs that are promoted by UI and CL&P.

C&LM programs provide significant benefits to UI and CL&P ratepayers, yet there is limited emphasis placed on promoting the conservation fund. The Department believes that there is a value in raising the general awareness about the conservation fund among all customers and that the ECMB should pursue a strategy to accomplish this goal. The Department recognizes that establishing a separate marketing budget to achieve this result would divert resources from other program activities. However, the Department believes that cost-effective actions can be taken at this time. Simple steps, such as the use of a conservation fund logo and a shift in program promotional language can begin this process. For example, instead of promoting conservation programs as utility-sponsored events, these initiatives should instead be marketed as "sponsored by the Conservation Fund and operated for the benefit of ratepayers by CL&P or UI" or similar language. This would preserve the link to CL&P and UI while introducing the concept of the conservation fund to customers. In addition, over time, other marketing dollars should be diverted to a general awareness effort regarding the fund. Ideally, the logo could be Connecticut-specific but related to other conservation fund logos that may be in use throughout New England.

Based on the foregoing, the Department will direct CL&P and UI to work with the ECMB to develop and implement a Conservation Fund logo for use on all C&LM marketing material. The ECMB must also develop a protocol for the use and placement of the Conservation Fund logo. In addition, the ECMB should consider how best to deliver the message that these programs are sponsored by the Conservation Fund, within the current marketing budget of these programs. The Conservation Fund logo must be in place for 2005 and must be used in all marketing and promotional material by 2006.

D. Load Management/Load Response

1. OCC Consultant Recommendations

The OCC consultant recommends that load management be funded out of rates, rather than through the C&LM fund. Report, p. 535; Tr. 4/12/04, p. 536. The Department shall continue to finance load management programs from the C&LM fund, which was established for load management as well as conservation purposes.

2. Load Response Supplemental Payments

In the Phase 1 Decision in this Docket, the Department withheld approval of the 2004 C&LM Plan proposed \$20 - \$40/kW supplemental payments to participants in the

ISO-NE Load Response Program, pending the results of the ISO-NE Request for Proposals (RFP) for reliability resources in Southwest Connecticut (SWCT). 2004 C&LM Plan, p. 244; Decision, p. 20. Given bidders' robust response of the ISO-NE RFP, the Department deems unnecessary the use of C&LM funds to finance supplemental reliability payments for summer 2004.[4]

In Phase 1 of this docket, there was considerable discussion of modifications to the Companies' proposed supplemental payments to potentially mitigate price spikes and high congestion costs in SWCT. Response to Interrogatory EL-35; Tr. 12/15/03, p. 80;. Late File Exhibit No. 2; Tr. 12/29/03, pp. 395-414. In Phase 2 of this docket, the Department convened a technical meeting April 20, 2004, with the Companies, ISO-NE, and members of ECMB to discuss straw proposals for supplemental incentives for participants in the ISO-NE Price Response Program in SWCT for summer 2004. At this time, the Department will not order supplemental Price Response payments for the ISO-NE Price Response program in SWCT in summer 2004; instead, the Department supports geographically targeted peak-load-reducing C&LM projects in SWCT. In a letter dated May 19, 2004, the Department indicated that it will initiate meetings with ISO-NE, the Companies, Department staff, and interested persons to investigate whether modifications can be made to the ISO-NE demand response program to mitigate high LMP and high FMCC charges in SWCT for 2005. These meetings will include discussions of proposals to encourage participation in the Companies' or ISO-NE load response programs.

E. AUDIT OF THE C&LM FUND

Pursuant to the Decision dated May 28, 2003, in Docket No. 03-01-01, DPUC Review of The Connecticut Light and Power Company's and The United Illuminating Company's Conservation and Load Management Programs and Budgets for Year 2003 and 2004, the Department required that an independent audit of the conservation and load management fund be conducted. Decision, p. 6. The Department will issue an RFP to have the audit commence in the fourth quarter of 2004. The scope of the audit will include a review of program operations, financial internal controls, a survey of vendors, and compliance with ECMB and Department directives.

F. EMPLOYEE SEVERANCE COSTS

In June of 2003, in response to pending legislation that threatened to reduce or eliminate C&LM funding, CL&P took steps to reduce its C&LM-related costs. These cost cutting efforts included reducing CL&P's C&LM staff. CL&P states that its parent, Northeast Utilities (NU), attempted to mitigate the impact of these terminations by hiring C&LM employees into other areas within NU. CL&P states that it incurred $1,210,580 in costs related to the severance of C&LM employees and that these payments were made pursuant to the NU system Severance Pay Plan agreement. Response to Interrogatory EL-1.

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[4] The resources selected by ISO-NE will provide approximately 125 MW of additional capacity beginning June 1, 2004, and up to 255 MW by the summer of 2007 from demand response resources, including emergency generation, load control, load response, and from conservation resources.

CL&P states that the use of C&LM funds for severance payments is justified because these employees were dedicated to C&LM activities. Further, CL&P states that the Department directed CL&P to proceed with extreme caution with regard to incurring C&LM-related costs beyond June 30, 2003, the time at which legislative action regarding the C&LM fund was pending. Therefore, CL&P states that it was complying with the Department's order when it incurred these severance costs. Id.

In June of 2003, there was tremendous uncertainty regarding the continued funding of C&LM activities. In light of these uncertainties, the Department directed CL&P to exercise caution regarding spending on C&LM activities. Decision dated May 28, 2003, in Docket No. 03-01-01, p. 2. CL&P took steps to contain C&LM costs, targeting the operation of C&LM programs as well as its C&LM-related payroll expense. Based on a review of this matter the Department finds that CL&P acted appropriately in taking the actions it did to curtail C&LM spending. Further, the Department finds that it is reasonable to fund the severance costs associated with C&LM employees with funds from the C&LM budget. Therefore, the Department approves $1,210,580 in costs related to the severance of C&LM employees.

IV. CONCLUSIONS AND ORDERS

A. Conclusion

The Department approves the proposed 2004 budgets and makes minor 2004 program modifications. The Department also approves $1,210,580 in costs related to the severance of CL&P C&LM employees. Commencing in the fourth quarter of 2004, the Department will issue an RFP to conduct an audit of the CL&M programs.

The Department has evaluated the major findings of the Office of Consumer Counsel report, Review of Connecticut's Conservation and Load Management Administrator Performance, Plans and Incentives. Based on this evaluation, the Department directs the Companies to work with the ECMB to modify the performance incentive mechanism; joint program delivery; and the process of setting program goals, tracking program performance and conducting program evaluations.

The Department will not authorize supplemental payments for reliability based load response participation. Instead this Decision establishes a collaborative process by which the Department, Companies, ISO-NE, and ECMB will investigate whether modifications can be made to the ISO-NE demand response program to mitigate high LMP and high FMCC charges in SWCT and to develop policy options for 2005.

B. Orders

1. The Companies shall market total resource benefits to customers for those programs and projects and projects that have substantial non-electric benefits. On or before August 20, 2004, Companies shall submit information to the Department, demonstrating how TR benefits are marketed comprehensively by Company employees and/or vendors for each program that has substantial non-electric savings.

2. In the 2005 C&LM filing, CL&P will adopt "Energy Blueprint" (new construction) and "Energy Opportunities" (existing structures) as C&I program names for marketing purposes. The 2005 C&LM filing will include a discussion of plans for developing joint marketing of C&I material and promotional activities.

3. In the 2005 C&LM filing, the ECMB and CL&P shall evaluate the benefits and make recommendations pertaining to consolidating the administration of some of the Company's C&I programs.

4. For the 2006 C&LM filing, the ECMB shall adopt the OCC Consultant's matrix as a guide to developing specific cross-sector performance incentives as well as the targets and milestone events within the residential and C&I programs.

5. The Companies shall develop a joint tracking analysis report for each C&LM program, to be submitted in the 2006 filing.

6. The Companies shall develop a joint TRM, to be submitted in the 2006 filing.

7. For the 2005 Annual C&LM filing, the Department directs the ECMB to develop a process that assures complete independence from the Companies in the selection and content of third party program evaluations.

8. As of the date of this Decision, the Companies are directed to send third party evaluation reports to the Department upon their completion.

9. For the 2006 Annual C&LM filing, the Companies shall integrate and reference third party evaluation results into the annual goal-setting, annual tracking documentation and TRM, as appropriate.

10. On or before January 1, 2005, the Companies shall implement a joint '800' number as discussed herein.

11. On or before January 1, 2005, UI and CL&P, in consultation with the ECMB, shall implement a Conservation Fund logo. The logo shall be used in all C&LM marketing material beginning in 2006.

12. On or before July 16, 2004, the Companies shall submit a final budget for 2004 as discussed herein.

Appendix 1

CROSS-SECTOR PERFORMANCE INCENTIVES

		Performance Indicator	Type	Target	Period	Incentive Weight	Verification
1	MWh	Annual incremental net MWh savings	PR	450,459	2004-05 cumulative	20.00%	Annual Process
2	Peak kW	Cumulative summer peak demand savings in SWCT	PR	76	2004-05 cumulative	20.00%	Annual Process
3	NRB	Present worth of lifetime net benefits (total resource benefits from electric, fossil and water savings minus total resource costs).	PR	$343,249,895	2004-05 cumulative	25.00%	Annual Process
		The following requires the Companies to meet 3 out of 4 Cross-Sector Activity Milestones (See Note 4)					
4	Reporting & Verification	Develop a Technical Reference Manual documenting prescriptive measures and characterizations, with procedures for updating as appropriate.	ACT		April 1, 2004	5%	DPUC
5	Reporting & Verification	Establish an annual process for independnet review and verification of administrator performance claims, particularly for PI 1 through 3.	ACT		Jan. 1, 2004		
6	Evaluation	Prepare and submit for Department approval a 3-year evaluation plan specifying tasks and schedule for market assessment, market share tracking and program evaluation.	ACT		Jan. 1, 2004		
7	Tracking & Reporting	Develop and launch an integrated, independently accessible electronic data tracking system for program results.	ACT		Jan. 1, 2005		
Total Weight						70%	

Note 1
To achieve any award for completion of C&I activity milestones, a minimum of 4 milestones must be completed. Each award is valued at $37,500.
Achieving 4 results in an award of $150,000. Completion of 5 results in an award of $
Completion of all 6 results in an award of $225,000.

COMMERCIAL & INDUSTRIAL PERFORMANCE INCENTIVES

	Program	Indicator	Type	Target	Period	Incentive Weight	Verification
1	SBEA Customers	Installion of 'X' no. of customers. See note 1.	PR	750	2004-05 Cumulative	2.50%	Annual Process
2	SBEA Comprehensiveness	Capture percentage of SBEA annual kWh impacts from non-standard measures. See notes 1 & 2.	PR	9.0%	2004-05 Cumulative	2.50%	Annual Process
3	Cool Savings	Capture percentage of kWh impacts among New Construction, Custom Services and Energy Opportunities Programs from cooling measures. See note 1.	PR	13.0%	2004-05 Cumulative	3.75%	Annual Process
4	Medium-Sized Customers	Capture percentage of projects among the Custom Services, Express and Energy Opportunities Programs from customers with average summer peak demand of less than 350 kW. See Note 1.	PR	40.0%	2004-05 Cumulative	3.75%	Annual Process
		The following would require that 4 of 6 Activity Milestones be met and would total 5% of the incentive.					
5	HVAC Tune-ups in SBEA	Begin delivering HVAC tune-ups as standard measure in SBEA throughout all targeted SWCT areas where program is delivered.	ACT	4 of 6 Milestones		5.00%	DPUC
6	SBEA Incentive Structure Improvements	Redesign SBEA positive-cash-flow, on-the-bill financing and cash incentive structure and begin implementation.	ACT	4 of 6 Milestones	May 1, 2003		
7	Lighting Minimum Efficiency	Substantially increase the minimum watt/sq.ft. lighting efficiency (lower numbers-higher efficiency) criteria to qualify for incentive to no worse than the IECC 2003 figures and proposed ASHRE 2004 (appox. 20-30% or better than ASHRAE 90.1 1999).	ACT	4 of 6 Milestones	July 1, 2004		
8	Non-electric benefits approach	Develop and adopt an approach to identify, communicate to customers and incorporate in project screening and rebate offers, significant non-electric benefits from selected customer measures for industrial customers.	ACT	4 of 6 Milestones	March 1, 2004		
9	Incentive review	Complete a review of opportunities for targeted modifications to incentive structures and levels in the New Construction, Custom Services, Express and Energy Opportunities Programs, by July 1, 2004. Institute appropriate recommendations by January 1, 2005.	ACT	4 of 6 Milestones	January 1, 2005		
10	Consolidate Programs	Expand Custom Services and Express Programs statewide and revamp to focus only on lost opportunities in existing buildings. Expand Energy Opportunities to all appropriate targeted SWCT areas (at least Norwalk/Stamford) and begin to deliver programs for existing customers as a single set of products and services rather than fragmented options.	ACT	4 of 6 Milestones			
					Total Weight	17.50%	

Note 1
The C&I Program result awards are scaled as follows
Below 75% of target the administrators earn no incentive. At 75% of target the administrators earn 50% of the total incentive.
Administrators earn 115% of the award if they achieve 120% of target or higher.
The award shall be scaled linearly between 50% and 100% of the incentive amount for performance between 75% and 100% of target,
and between 100% and 115% of the incentive between 100% and 120% of target.

Note 2
Non-standard measures are defined as customized site-specific measures rather than those measures typically offered through the program as standard practice. They do not include lighting fixtures unless a fixture layout is performed. They do not include HVAC tune-ups or normally offered refrigeration measures (e.g., anti-sweat heater and evaporator controls and economizers).

Note 3
To achieve any awards for completion of C&I activity milestones, a minimum of 4 activities must be completed. Each award is valued at $37,500. Achieving 4 results in an award of $150,000.
Completion of 5 results in an award of $187,500. Completion of all 6 items results in an award of $225,000.

Appendix 1

RESIDENTIAL PERFORMANCE INCENTIVES

	Program	Performance Indicator	Type	Target	Period	Incentive Weight	Verification
1	Energy Star Homes	Market share of completed homes meeting program standards (i.e., Energy Star certified with documentation of proper sizing oand installation of new central air conditioner.	MI	17.5%	2005	2.50%	Annual Process
2	Heating & Cooling	Market share of SEER 13 central air conditioners that are properly sized and charged.	MI	30%	2005	2.50%	Annual Process
3	Energy Star Lighting	Retail sales of CFLs	MI	.75 per hsehld.	2005	2.50%	Annual Process
	The following would require that 7 of 10 activity milestones be met and would total 5% of the incentive.						
4	All Residential Programs	Each residential program has one design that is implemented identically across the state (except for targeting to SWCT, which will itself be identical across that region).	ACT		April 1, 2004	5.00%	DPUC
5	Energy Star Lighting	Participate in at least 3 CFL buydowns with manufacturers and/or major retailers.	ACT		Oct. 1, 2004		
6	Energy Star Appliances	Replace consumer rebates for appliances with manufacturer and/or retailers incentive offerings.	ACT		June 1, 2004		
7	Energy Star Homes	Make offers for construction of at least 75% of homes to program standards to at least 3 of the 10 largest builders in the state.	ACT		May 1, 2004		
8	Energy Star Homes	Complete and begin implementing new protocols for reducing the number of field inspections/performance tests of participating homes.	ACT		April 1, 2004		
9	Heating & Cooling	Train individuals representing at least 100 different HVAC firms in the state on use of Manual J and proper equipment sizing.	ACT		May 1, 2004		
10	Heating & Cooling	Train individuals representing at least 200 different HVAC firms in the state on proper use of Manual J and proper equipment sizing.	ACT		Jan. 1, 2005		
11	Heating & Cooling	Design and launch (i.e., announce to industry and begin training) a new duct sealing initiative targeted at existing homes in SWCT.	ACT		July 1, 2004		
12	Heating & Cooling	Announce offer of new furnace fan rebate to HVAC industry (in conjunction with the gas industry if possible).	ACT		July 1, 2004		
13	Low Income	Develop new measure installation protocols that ensure all cost-effective measures are installed in low income homes and train CAPs and any other installation contractors on their use.	ACT		June 1, 2004		
					Total Weight	12.50%	

Appendix 2

UI and CL&P C&LM Programs	Original Budget	Revised Budget	$ Increase	% Increase
	RESIDENTIAL			
Residential Retail Lighting	$2,898,368	$5,266,785	$2,368,417	81.72%
Energy Star Appliances	$1,182,368	$2,145,845	$963,477	81.49%
Appliance Retirement (inc. room AC)	$1,065,257	$2,284,293	$1,219,036	114.44%
Customer Initiated Projects	$500,000	$1,000,000	$500,000	100.00%
Total - Consumer Products	$5,645,993	$10,696,923	$5,050,930	89.46%
Residential New Construction	$1,173,015	$2,991,432	$1,818,417	155.02%
Residential Heating & Cooling	$1,816,072	$3,414,036	$1,597,964	87.99%
Sub Total RESIDENTIAL	**$8,635,080**	**$17,102,391**	$8,467,311	98.06%
	COMMERCIAL & INDUSTRIAL			
New Const./Energy Blueprint	$5,572,152	$10,999,576	$5,427,424	97.40%
Custom Services	$5,650,000	$8,600,000	$2,950,000	52.21%
Express Services	$1,100,000	$1,500,000	$400,000	36.36%
C&I RFP	$4,050,000	$6,722,128	$2,672,128	65.98%
Energy Opportunities	$1,757,126	$3,160,799	$1,403,673	79.88%
O&M	$1,360,220	$2,406,706	$1,046,486	76.94%
Services (BOC, Training)	$0	$0	$0	
RFP	$0	$0	$0	
Small Business	$3,853,492	$7,022,604	$3,169,112	82.24%
Sub Total C&I	**$23,342,990**	**$40,411,813**	$17,068,823	73.12%
	OTHER - EDUCATION			
SmartLiving Catalog	$0	$0	$0	
SmartLiving Center	$580,839	$758,085	$177,246	30.52%
eeSmarts (K-12 Education)	[illegible]	[illegible]	[illegible]	[illegible]
Residentail Audits-Non WRAP	$30,000	$35,000	$5,000	16.67%
Community Based program (SWCT)	$295,168	$345,641	$50,473	17.10%
Contingency from SLC	$420,000	$420,000	$0	0.00%
Sub Total Education	**$1,774,682**	**$2,139,142**	$364,460	20.54%
	OTHER - SPECIAL NEEDS			
Low Income-En. Care/WRAP/UI Helps	$3,772,217	$6,523,149	$2,750,932	72.93%
Municipal Energy & Schools	$1,404,000	$3,702,500	$2,298,500	163.71%
Sub Total - Special Needs	**$5,176,217**	**$10,225,649**	$5,049,432	97.55%
	OTHER PROGRAMS/REQUIREMENTS			
Institute for Sustainable Energy (ECSU)	$850,211	$839,035	-$11,176	-1.31%
Energy Conservation Loan Fund	$165,000	$209,250	$44,250	26.82%
Heat Pump Water Heaters	$200,000	$250,000	$50,000	25.00%
Billing System Conv.: On-bill financing	$105,000	$105,000	$0	0.00%
C&LM Loan Defaults	$55,000	$5,000	-$50,000	-90.91%
Sub Total - Programs/Requirements	**$1,375,211**	**$1,408,285**	$33,074	2.41%
	OTHER - LOAD MANAGEMENT			
ISO Load Response Supp. Payments	$1,071,000	$1,779,756	$708,756	66.18%
ISO Load Response Program Support	$300,000	$400,000	$100,000	33.33%
Demand Reduction	$435,000	$785,000	$350,000	80.46%
Load Reduction kW Incentives	$0	$0	$0	
Power Factor	$0	$2,000,000	$2,000,000	
Time of Use Program	$0	$0	$0	
Wait Until 8:00	$200,000	$475,000	$275,000	137.50%
Sub Total - Load Management	**$2,006,000**	**$5,439,756**	$3,433,756	171.17%
	OTHER - RENEWABLES AND RD&D			
Renewables Incentives	$200,000	$800,000	$600,000	300.00%
Research Dev. & Dem.	$1,074,000	$1,723,000	$649,000	60.43%
Sub Total - Renewables & RD&D	**$1,274,000**	**$2,523,000**	$1,249,000	98.04%
	OTHER - ADMINISTRATIVE & PLANNING			

DOCKET NO. 03-11-01 DPUC REVIEW OF CL&P AND UI CONSERVATION AND LOAD MANAGEMENT PLAN FOR YEAR 2004 – PHASE II

This Decision is adopted by the following Commissioners:

John W. Betkoski, III

Donald W. Downes

Jack R. Goldberg

CERTIFICATE OF SERVICE

The foregoing is a true and correct copy of the Decision issued by the Department of Public Utility Control, State of Connecticut, and was forwarded by Certified Mail to all parties of record in this proceeding on the date indicated.

Louise E. Rickard Acting Executive Secretary Department of Public Utility Control	Date

DSMRM

Demand-Side Management Cost Recovery Mechanism

APPLICABLE TO: Residential Service Rate RS, Volunteer Fire Department Rate VFD, General Service Rate GS, Small Time-of-Day Service Rate STOD, Large Power Rate LP, and Large Commercial/Industrial Time-of-Day Rate LCI-TOD. Industrial customers served under Large Power Rate LP, and Large Commercial and Industrial Time-of-Day Rate LCI-TOD, who elect not to participate in a demand-side management program hereunder shall not be assessed a charge pursuant to this mechanism.

The monthly amount computed under each of the rate schedules to which this Demand-Side Management Cost Recovery Mechanism is applicable shall be increased or decreased by the DSM Cost Recovery Component (DSMRC) at a rate per kilowatt hour of monthly consumption in accordance with the following formula:

DSMRC = DCR + DRLS + DSMI + DBA

Where: **DCR = DSM COST RECOVERY**. The DCR shall include all expected costs which have been approved by the Commission for each twelve-month period for demand-side management programs which have been developed through a collaborative advisory process ("approved programs"). Such program costs shall include the cost of planning, developing, implementing, monitoring, and evaluating DSM programs. Program costs will be assigned for recovery purposes to the rate classes whose customers are directly participating in the program. In addition, all costs incurred by or on behalf of the collaborative process, including but not limited to costs for consultants, employees and administrative expenses, will be recovered through the DCR. Administrative costs that are allocable to more than one rate class will be recovered from those classes and allocated by rate class on the basis of the estimated budget from each program. The cost of approved programs shall be divided by the expected kilowatt-hour sales for the upcoming twelve-month period to determine the DCR for such rate class.

DRLS = DSM REVENUE FROM LOST SALES

DSMRM

Demand-Side Management Cost Recovery Mechanism

included in such energy charges. The non-variable revenue requirement for each of the customer classes that are billed under demand and energy rates (Rate LP, Rate LCI-TOD, and Rate STOD) is defined as the weighted average price per Kwh represented by the composite of the expected billings under the respective demand and energy charges in the upcoming twelve-month period, after deducting the variable costs included in the energy charges.

The lost revenues for each customer class shall then be divided by the estimated class sales (in Kwh) for the upcoming twelve-month period to determine the applicable DRLS surcharge. Recovery of revenue from lost sales calculated for a twelve-month period shall be included in the DRLS for 36 months or until implementation of new rates pursuant to a general rate case, whichever comes first. Revenues from lost sales will be assigned for recovery purposes to the rate classes whose programs resulted in the lost sales.

Revenues collected hereunder are based on engineering estimates of energy savings, expected program participation and estimated sales for the upcoming twelve-month period. At the end of each such period, any difference between the lost revenues actually collected hereunder and the lost revenues determined after any revisions of the engineering estimates and actual program participation are accounted for shall be reconciled in future billings under the DSM Balance Adjustment (DBA) component.

A program evaluation vendor will be selected to provide evaluation criteria against which energy savings will be estimated for that program. Each program will be evaluated after implementation and any revision of the original engineering estimates will be reflected in both (a) the retroactive true-up provided for under the DSM Balance Adjustment and (b) the prospective future lost revenues collected hereunder.

DSMI = DSM INCENTIVE. For all Energy Impact Programs except Direct Load Control, the DSM incentive amount shall be computed by multiplying the net resource savings expected from the approved programs which are to be installed during the upcoming twelve-month period times fifteen (15) percent, not to exceed five (5) percent of program expenditures. Net resource savings are defined as program benefits less utility program costs and participant costs where program benefits will be calculated on the basis of the present value of KU's avoided costs over the expected life of the program, and will include both capacity and energy savings. For Energy Education and Direct Load Control Programs, the DSM incentive amount shall be computed by multiplying the annual cost of the approved programs which are to be installed during the upcoming twelve-month period times five (5) percent.

The DSM incentive amount related to programs for Residential Service Rate RS, Volunteer Fire Department Service VFD, General Service Rate GS, Small Time-of-Day Rate STOD, Rate LP, and Large Commercial and Industrial Time-of-Day Rate LCI-TOD, shall be divided by the expected kilowatt-hour sales for the upcoming twelve-month period to determine the DSMI for such rate class. DSM incentive amounts will be assigned for recovery purposes to the rate classes whose programs created the incentive.

Kentucky Utilities Company

DSMRM

Demand-Side Management Cost Recovery Mechanism

DBA = DSM BALANCE ADJUSTMENT. The DBA shall be calculated on a calendar year basis and is used to reconcile the difference between the amount of revenues actually billed through the DCR, DRLS, DSMI and previous application of the DBA and the revenues which should have been billed, as follows:

(1) For the DCR, the balance adjustment amount will be the difference between the amount billed in a twelve-month period from the application of the DCR unit charge and the actual cost of the approved programs during the same twelve-month period.

(2) For the DRLS the balance adjustment amount will be the difference between the amount billed during the twelve-month period from application of the DRLS unit charge and the amount of lost revenues determined for the actual DSM measures implemented during the twelve-month period.

(3) For the DSMI, the balance adjustment amount will be the difference between the amount billed during the twelve-month period from application of the DSMI unit charge and the incentive amount determined for the actual DSM measures implemented during the twelve-month period.

(4) For the DBA, the balance adjustment amount will be the difference between the amount billed during the twelve-month period from application of the DBA and the balance adjustment amount established for the same twelve-month period.

The balance adjustment amounts determined on the basis of the above paragraphs (1)-(4) shall include interest applied to the monthly amounts, such interest to be calculated at a rate equal to the average of the "3-month Commercial Paper Rate" for the immediately preceding 12-month period. The total of the balance adjustment amounts shall be divided by the expected kilowatt-hour sales for the upcoming twelve-month period to determine the DBA for such rate class. DSM balance adjustment amounts will be assigned for recovery purposes to the rate classes to which over- or under-recoveries of DSM amounts were realized.

The filing of modifications to the DSMRC which require changes in the DCR component shall be made at least two months prior to the beginning of the effective period for billing.

Modifications to other components of the DSMRC shall be made at least thirty days prior to the effective period for billing. Each filing shall include the following information as applicable:

(1) A detailed description of each DSM program developed by the collaborative process, the total cost of each program over the twelve-month period, an analysis of expected resource savings, information concerning the specific DSM or efficiency measures to be installed, and any applicable studies which have been performed, as available.

Kentucky Utilities Company

DSMRM

Demand-Side Management Cost Recovery Mechanism

(2) A statement setting forth the detailed calculation of the DCR, DRLS, DSMI, DBA and DSMRC.

Each change in the DSMRC shall be placed into effect with bills rendered on and after the effective date of such change.

Kentucky Utilities Company

DSMRM

Demand-Side Management Cost Recovery Mechanism

APPLICABLE TO:

Residential Service Rate RS, Volunteer Fire Department Service Rate VFD, General Service Rate GS, Small Time-of Day Rate STOD, Large Power Rate LP, and Large Commercial and Industrial Time-of-Day Rate LCI-TOD.

DSM Cost Recovery Component (DSMRC):

Residential Service Rate RS and Volunteer Fire Department Service VFD	Energy Charge
DSM Cost Recovery Component (DCR):	0.084 ¢/Kwh
DSM Revenues from Lost Sales (DRLS):	0.002 ¢/Kwh
DSM Incentive (DSM):	0.003 ¢/Kwh
DSM Balance Adjustment (DBA):	(0.017) ¢/Kwh
DSMRC Rate RS:	0.072 ¢/Kwh

General Service Rate GS	Energy Charge
DSM Cost Recovery Component (DCR):	0.023 ¢/Kwh
DSM Revenues from Lost Sales (DRLS):	0.009 ¢/Kwh
DSM Incentive (DSM):	0.000 ¢/Kwh
DSM Balance Adjustment (DBA):	(0.008)¢/Kwh
DSMRC Rate GS:	0.024 ¢/Kwh

Kentucky Utilities Company

DSMRM

Demand-Side Management Cost Recovery Mechanism

DSM Cost Recovery Component (DSMRC):
(Continued)

Large Power Rate LP and Small Time-of-Day Service Rate STOD	Energy Charge
DSM Cost Recovery Component (DCR):	0.004 ¢/Kwh
DSM Revenues from Lost Sales (DRLS):	0.000 ¢/Kwh
DSM Incentive (DSM):	0.000 ¢/Kwh
DSM Balance Adjustment (DBA):	(0.001)¢/Kwh
DSMRC Rate LP:	0.003 ¢/Kwh

Large Commercial/Industrial Rate LCI-TOD	Energy Charge
DSM Cost Recovery Component (DCR):	0.000 ¢/Kwh
DSM Revenues from Lost Sales (DRLS):	0.000 ¢/Kwh
DSM Incentive (DSM):	0.000 ¢/Kwh
DSM Balance Adjustment (DBA):	0.000 ¢/Kwh
DSMRC Rate TOD:	0.000 ¢/Kwh

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ADJUSTMENTS TO THE DEMAND-SIDE MANAGEMENT BALANCE ADJUSTMENT COMPONENT ("DBA") OF THE DEMAND SIDE MANAGEMENT COST RECOVERY MECHANISM OF LOUISVILLE GAS AND ELECTRIC COMPANY AND KENTUCKY UTILITIES COMPANY	))))))	CASE NO. 2003-00080

<u>O R D E R</u>

On March 3, 2004, Lousiville Gas and Electric Company ("LG&E") and Kentucky Utilities Company ("KU") filed proposed changes to the Demand-Side Management Balance Adjustment ("DBA") component of their Demand-Side Management Cost Recovery ("DSMCR") tariffs. The changes are based on LG&E's and KU's over- or under-recovery of demand-side management program costs incurred in calendar year 2003. The proposed tariffs include an effective date of April 2, 2004. The revised DBA components, with the proposed changes, will remain in effect through March 31, 2005.

LG&E's proposed tariffs include reduced DBA charges for gas customers served under Residential Rate RGS, the Residential Summer Air Conditioning Rider, Commercial Rate CGS, Rate G-6, Rate G-7, Rate TS, Rate FT, and the Commercial Summer Air Conditioning Rider. Its proposed tariffs also include reduced DBA charges for electric customers served under Residential Rate R and increased DBA charges for electric customers served under General Service Rate GS, Large Commercial Rate LC, and Large Commercial Time-of-Day Rate LC-TOD. KU's proposed revisions result in increased DBA charges to customers served under Residential Rates RS and FERS and General Service Rate GS and reduced DBA charges for customers served under its Light & Power Rate LP.

Based on its review of the revised tariffs and supporting calculations of LG&E's and KU's over- and under-recoveries of costs in 2003, the Commission finds that the proposed tariff changes are reasonable and should be approved effective April 2, 2004.

IT IS THEREFORE ORDERED that:

1. LG&E's and KU's proposed changes to their DSMRC tariffs are approved effective April 2, 2004.

2. Within 20 days of the date of this Order, LG&E and KU shall file their revised DSMRC tariffs that show the date issued and that show they were issued by authority of this Order.

Done at Frankfort, Kentucky, this 25th day of March, 2004.

By the Commission

ATTEST:

Executive Director

CA-IR-323

Ref: HECO T-12, page 28.

Is Mr. Violette aware of any US gas or electric utilities that have received regulatory approval for the two-part incentive mechanism that he recommends in this proceeding?

If so, please provide the names of the utilities and cite the related commission orders approving such mechanisms.

Is Mr. Violette aware of any US gas or electric utilities that have been authorized to earn a return on DSM expenditures that are booked to expense accounts?

If so, please provide the names of the utilities and cite the related commission orders approving such treatments.

HECO Response:

a. As a note, the proposed DSM utility incentives mechanism does have two parts, however, only one part deals with incentives. The first element of the proposal -- recovery of the shortfall in fixed cost contribution simply makes the utility whole with respect to its investment in DSM that results in lower sales. The second element of the proposal deals with incentives whereby there would be a return on program costs.

With respect to lost margins, several decisions regarding recovery of lost margins for gas utilities refer to the "rolling period method" proposed by Dr. Violette. These decisions (cited in the testimony) also refer to the fact that the approach proposed is consistent with precedent in Massachusetts, could be applied to electric companies, and would be relatively simple to administer. These citations are presented in the witness' testimony on pages 8 and 10.

After restructuring in Massachusetts, lost revenues was not deemed to be a significant issue for distribution electric utilities as their generation units were sold off. While lost revenues has declined in importance for distribution-only utilities, the distribution electric utilities in Massachusetts do continue to earn an incentive on their DSM expenditures.

b. See response to part a. above.

c. With respect to the second part of the question concerning whether Dr. Violette is aware of any US gas or electric utilities that have been authorized to earn a return on DSM [redacted] of all the utilities in the United States. However, based on recent work, the following is known:

1) California awarded incentives to gas and electric utilities based on meeting various milestones. The costs of these DSM activities were booked to the appropriate accounts, and while Dr. Violette cannot state with certainty, some of these expenditures were likely booked as expenses.

CA-IR-324

<u>Ref: HECO T-12, page 31, footnote 24.</u>

Please provide a copy of the data obtained from the S&P Compustat data service, along with all workpapers used to develop the rate-of-return estimates shown in the table at page 32.

<u>HECO Response:</u>

The S&P Compustat data contains raw data and is voluminous. It will be provided electronically and under a separate cover. The files will be labeled as follows:

- CA-IR-324_S&P Compustat data
- CA-IR-324_rate of return workpapers

CA-IR-325

Ref: HECO T-12, page 32, line 13.

a. In using the term "agreed-upon level of kWh savings," did Mr. Violette envision some future discussion among interested parties where agreement would be reached on a target level of savings going forward? Explain.

b. Does the term mean that the target has already been established?

c. If the response to subpart (b) of this information request is yes, in what forum was the target established and who were the participants?

d. If not, please explain.

HECO Response:

a. No, the use of "agreed-upon level of kWh savings' was not intended to signal a discussion of a target level of DSM savings going forward. Instead, it simply refers to the final level of kWh savings from HECO's proposed energy efficiency DSM programs determined to be reasonable as the result of this rate case proceeding.

b. Yes, the target estimate of kWh savings, 54.7 GWh, has been established for the purposes of HECO's direct testimony. See HECO T-11 page 4.

c. As indicated in HECO T-11, page 8, lines 2 through 9, the DSM programs and impacts were developed with input from the IRP-3 Demand-Side Technical Committee. The members of the IRP-3 Demand-Side Technical Committee are as follows: Steve Alber (DBEDT), Keith Block (HECO), Michael Chong (ASHRAE/AES Design Group), Rolf Christ (Hawaii Solar Energy Association), Norris Creveston (HECO)[1], Chris Cunha (Dept. of Environmental Services), Henry Curtis (Life of the Land), Michael Hamnett (UH), James Harwood (Manoa

[1] Mr. Creveston has since retired from HECO. His replacement is Mr. Gary Ambach, Director of the Customer Efficiency Programs Division.

[redacted]

Board), Steve Holmes (City and County of Honolulu), Cully Judd (Hawaii Solar Energy Association), Wayne Judd (Sheraton Hotels), Cheryl Kikuta (DCCA-Consumer Advocate's Office), Fred Kohloss, Manny Lanuevo (Dept. of Transportation), Bobbie Lau (Colliers Monroe Friedlander), Jeff Mikulina (Sierra Club), Mary Miller (American Lung Association), Kris Nakagawa (PUC), Lester Nakata (Oahu Sales), Liz Raman (DBEDT),

CA-IR-326

<u>Ref: HECO T-12, pages 34-35.</u>

Please provide support for the statement that the financial community is opposed to, or unsupportive of the capitalization of DSM expenditures. Specifically, provide copies of all reports or studies that demonstrate that the financial community reacts unfavorably to this approach.

<u>HECO Response:</u>

HECO has no written reports or studies that demonstrate that the financial community reacts unfavorably to the capitalization of DSM expenditures. Some financial analysts, however, agree that a regulatory asset created for DSM program cost recovery is riskier than a capital asset such as a power plant. This perspective reflects that fact that regulatory assets <u>can</u> pose a cost recovery risk, depending on how confident the rating agencies and analysts are that the specific asset is safe from reconsideration by the PUC, legal challenge by third parties, or other unforeseen factors. Thus, regulatory assets have an additional hurdle to clear before they are on equal footing with capital assets. It could be argued that this very fact suggests that regulatory assets are viewed less favorably by the financial community, although it may vary on a case-by-case basis and could be influenced by which analysts are offering their opinions on a given asset or utility portfolio.

CA-IR-327

a. Is Mr. Violette aware of any US gas or electric utility that capitalizes DSM expenditures and recovers both the amortization and return on investment through rates?

b. If so, please provide the names of such utility and provide details regarding the program cost accounting.

HECO Response:

a. Dr. Violette is not presently aware of any U.S. gas or electric utility that capitalizes DSM expenditures and recovers both the amortization and return on investment through rates.

b. Not applicable.

CA-IR-328

a. For each existing and proposed DSM program, please state whether the services are delivered by personnel employed directly by HECO or by third-party service companies working under contract to HECO.

b. What portion of the test year program costs associated with each program relate to costs

billed by third-party service providers?

c. For programs delivered by third-party providers, please discuss in qualitative and

REWH: 37.3%

RNC: 28.7%

RCEA: 92.7%

RLI: 24.3%

ESH: 22.4%

RDLC: 37.8%

CIDLC: 7.2%

c. Not applicable. All DSM programs are delivered by HECO personnel with support from third-party service providers.

CA-IR-329

Please explain how HECO balances the interests of participants and non-participants when deciding to increase the size of its DSM budgets. Regarding the decision to more than double the energy savings in 2005 compared to 2003, provide all analyses performed by or for HECO that demonstrate that the increase in rates charged to non-participants in 2005 and after as a result of the proposed expansion of the DSM programs will be reasonable.

<u>HECO Response:</u>

The interests of HECO's customers, both DSM program participants and non-participants, are incorporated in HECO's Integrated Resource Planning process which identified DSM as one of the preferred, least cost options for meeting the long-term energy needs of our customers. This is the case for both the IRP-2 Plan that was completed by the Company in 1997 (Docket No. 95-0347) and the IRP-3 plan currently being developed.

The IRP preferred plans balance the following objectives:

- Meet Customer Electrical Needs at Lowest Reasonable Cost
- Increase Fuel Diversity for the Electrical System

resource plan, and the stated financial impacts on all customers.

The balance that the CA wants to explore in this IR appears to be the different economic effects of the DSM Programs on participants vs. non-participants. Those differences occur because participants receive DSM program rebates for their financial investment in eligible energy conservation measures, and benefit from lower energy bills that result from energy savings. Program costs are recovered from both participants and non-participants, and both participants and non-participants receive the long-term energy and capacity deferral benefits that result from the DSM programs.

HECO recognizes that the difference in economic effects exists and has intentionally developed a wide-ranging array of DSM measures under its existing and proposed DSM programs (and has budgeted funds to market those measures) in order to provide the large majority of customers with opportunities to participate. Typically, the DSM measures are also cost-effective over their service lives from the perspective of the participant. Since HECO has attempted to reduce economic and market barriers to participation, actual involvement in HECO's DSM programs is a matter of customer choice, and participants and non-participants are largely self-selecting.

The analysis that determines whether or not the increase in rates for all customers (including participants and non-participants) is reasonable involves conducting the benefit/cost tests developed for the California Public Utilities Commission that are identified and defined in the *Standard Practice Manual Economic Analysis of Demand-Side Management Programs.* HECO uses the Total Resource Cost (TRC) Test to determine whether customers and the utility together are economically better off by acquiring DSM resources than by not acquiring DSM resources. The TRC test compares the utility and participant costs of a DSM program against the benefits received in terms of avoided costs for plant capacity and energy production. If the benefits are greater than the costs, the DSM program is cost-effective and all customers, including the non-participants, are better off with the utility acquiring DSM resources.

The Ratepayer Impact Measure (RIM) test evaluates the effect of the DSM programs on utility rates. HECO's DSM programs typically do not pass the RIM test because the cost of the DSM programs is recovered from all ratepayers. Thus, utility rates typically increase above pre-DSM program levels. However, because the DSM programs pass the TRC test, the rate increases over the long-term are less than if the DSM resources were not acquired.

CA-IR-330

Ref: HECO T-12, page 48, line 8.

Please identify and discuss the risks that utilities face when they implement DSM programs.

HECO Response:

Implementing a DSM program is like introducing any new product or service into a market. Just as all new product introductions are not successful, not all DSM programs reach their anticipated targets. Implementation can be more difficult and costly than expected. Risk that utilities face when they implement DSM programs include 1) limitations on the availability of end-use market baseline data, 2) market risks (participation assumptions), 3) infrastructure risks (i.e., vendor capacity to meet the demand created by the DSM programs), and 4) performance risks (i.e., ability of equipment to improve energy efficiency). The expected savings will vary depending on the availability of market data and the characteristics of those customers that choose to participate in the program (and these participants may differ from those assumed to participate when planning the program). Attainment of participation rates might be more difficult than anticipated, requiring a change in mode of marketing and/or the marketing message.

In general, implementing a successful DSM program is challenging. A lot of hard work goes into program planning and delivery, and there are unplanned circumstances that can prevent a program from achieving its full objectives. Some observers have the opinion that all DSM programs are fool proof and that there are no difficulties to be overcome in implementation. This is simply incorrect. A DSM program is a new service being offered into the market and, as with any new service, market vagaries can influence its success. As a result, within a portfolio of DSM programs, some might exceed expectations, some might just meet expectations and some will not meet expectations. The utility may face regulatory risks for those programs that do not meet expectations, even though best efforts were undertaken to make the program successful.

A discussion of the risk/reward relationship related to DSM is ongoing in California

The California PUC has made the following statements in this regard (see CPUC Decision D.05-01-055, January 27, 2005):

"We concur…that we need to consider a risk/reward mechanism for energy efficiency program administration in this proceeding. As indicated in prior rulings and decisions, we intend to do so in careful coordination with the development of an overall procurement incentive framework:

In D.02-10-062, we expressed our preference to adopt a uniform incentive mechanism to provide an opportunity for utilities to balance risk and reward in the long-term procurement process.

CA-IR-331

Please provide the following statistical data for each available month of 2005:

a. Actual KWH sales by rate code.

b. Actual employee levels by RA.

c. Actual direct labor hours worked by RA.

d. Actual non-labor expenses by RA.

HECO Response:

The following statistical data is being provided for January and February 2005:

[illegible]

Hawaiian Electric Company, Inc.

RECORDED KWH SALES BY RATE SCHEDULE

	Jan-05	Feb-05
R	178,886,897	153,695,802
E	1,802,577	1,499,119
G	28,156,100	26,715,065
J	161,694,320	144,827,704
H	4,438,850	4,059,564
P	247,865,807	223,153,085
F	3,390,299	2,837,240
Total	626,234,850	556,787,579

635 Employee Count by Department/Division within VP Function as of 01/31/2005

Includes Regular, Part-time, Temporary, Leaves, and Probationary Employees

Report Parameters
AsOfDate: 01/31/2005
District: P HAWAIIAN ELECTRIC COMPANY
VP Function: *
Department: *
Division: *

HAWAIIAN ELECTRIC COMPANY:

CLASSIFICATION GROUPINGS

FUNCTION	DEPT	RA	BU	EXEC	MERIT	TOTAL
CORPORATE EXCELLENCE						
	COMPENSATION AND BENEFITS					
		PFC COMPENSATION	0	0	1	1
		PPW DISABILITY MANAGEMENT	0	0	3	3
		PFB EMPL BENEFITS & HLTH SVCS	0	0	9	9
		Subtotal for COMPENSATION AND BENEFITS	**0**	**0**	**13**	**13**
	INDUSTRIAL RELATIONS					
		PPA ADMINISTRATION	0	0	3	3
		PPI LABOR REL & WAGE ADMIN	0	0	6	6
		Subtotal for INDUSTRIAL RELATIONS	**0**	**0**	**9**	**9**
	SAFETY, SECURITY & FACILITIES					
		PHA ADMINISTRATION	0	0	2	2
		PFS CORPORATE SAFETY	4	0	7	11
		PHB FACILITIES OPERATIONS	14	0	1	15
		PHF FACILITIES PLANNING	1	0	4	5
		PHS SECURITY	0	0	19	19
		Subtotal for SAFETY, SECURITY & FACILITIES	**19**	**0**	**33**	**52**
	VP CORPORATE EXCELLENCE					
		P6V VP CORPORATE EXCELLENCE	0	1	1	2
	WORKFORCE STAFFING & DEVELOP					
		PFA ADMINISTRATION	0	0	4	4
		PFD CLIENT SERVICES & CONSULTING	0	0	10	10
		PFI ORGANIZ DEV & CONTIN IMPRVMT	0	0	3	3
		Subtotal for WORKFORCE STAFFING & DEVELOP	**0**	**0**	**17**	**17**
Total for CORPORATE EXCELLENCE			**19**	**1**	**73**	**93**

CORPORATE RELATIONS

635 Employee Count by Department/Division within VP Function as of 01/31/2005

Includes Regular, Part-time, Temporary, Leaves, and Probationary Employees

Report Parameters					
	AsOfDate:	01/31/2005			
	District:	P	HAWAIIAN ELECTRIC COMPANY	Department:	*
	VP Function:	*		Division:	*

HAWAIIAN ELECTRIC COMPANY:

FUNCTION	DEPT	RA	BU	EXEC	MERIT	TOTAL
			CLASSIFICATION GROUPINGS			
	CORPORATE COMMUNICATIONS					
	PQC	CORPORATE COMMUNICATIONS	1	0	8	9
	VP CORPORATE RELATIONS					
	P1V	VP CORPORATE RELATIONS	0	1	1	2
	Total for CORPORATE RELATIONS		**1**	**1**	**9**	**11**
CUSTOMER SOLUTIONS						
	CUSTOMER TECH APPLICATIONS					
	PSR	CUSTOMER TECH APPLICATIONS	1	0	8	9
	ENERGY SERVICES					
	PSA	ADMINISTRATION	0	0	3	3
	PSD	CUSTOMER EFFICIENCY PROGRAM	1	0	5	6
	PSP	PRICING	0	0	5	5
		Subtotal for ENERGY SERVICES	**1**	**0**	**13**	**14**
	FORECASTS & RESEARCH					
	PSM	FORECASTS & RESEARCH	0	0	10	10
	INTEGRATED RESOURCE PLNG					
	PYP	INTEGRATED RESOURCE PLANNING	0	0	4	4
	MARKETING SERVICES					
	PSN	MARKETING SERVICES	0	0	11	11
	VP CUSTOMER SOLUTIONS					
	P1W	CUSTOMER SOLUTIONS	0	1	1	2
	Total for CUSTOMER SOLUTIONS		**2**	**1**	**47**	**50**
ENERGY DELIVERY						
	CONSTRUCTION & MAINTENANCE					
	PDA	ADMINISTRATION	0	0	5	5

635 En. oyee Count by Department/Divisio within VP Function as of 01/31/20

Includes Regular, Part-time, Temporary, Leaves, and Probationary Employees

Report Parameters
AsOfDate: 01/31/2005
District: P HAWAIIAN ELECTRIC COMPANY
VP Function: *
Department: *
Division: *

HAWAIIAN ELECTRIC COMPANY:

FUNCTION	DEPT	RA		BU	EXEC	MERIT	TOTAL
				CLASSIFICATION GROUPINGS			
		PDC	CONTROL SECTION	8	0	1	9
		PDH	CUSTOMER DEMAND	3	0	2	5
		PDK	EAST OVERHEAD-KOOLAU	23	0	0	23
		PDL	EAST OVERHEAD-WARD	41	0	0	41
		PDF	FIELD OPERATION	20	0	0	20
		PDM	MAINTENANCE DEMAND	0	0	2	2
		PDP	PLANNING	0	0	11	11
		PDS	SUPPLY DEMAND	0	0	9	9
		PDD	TRAINING SECTION	15	0	2	17
		PDU	UNDERGROUND	23	0	0	23
		PDV	VEGETATION MANAGEMENT	0	0	2	2
		PDJ	WEST OVERHEAD	52	0	0	52
			Subtotal for CONSTRUCTION & MAINTENANCE	**185**	**0**	**34**	**219**
ENGINEERING							
		PBA	ADMINISTRATION	4	0	3	7
		PBP	PROJECT MANAGEMENT	0	0	6	6
		PBT	STRUCTURAL	5	0	12	17
		PBY	SUBST,PROTECTION&TELECOM	3	0	17	20
		PBE	T&D ENGINEERING	3	0	20	23
		PBZ	T&D TECHNICAL SERVICES	2	0	7	9
			Subtotal for ENGINEERING	**17**	**0**	**65**	**82**
SUPPORT SERVICES							
		PVA	ADMINISTRATION	0	0	5	5
		PVL	ELECTRICAL & WELDING SERVICES	12	0	1	13
		PVF	FLEET	23	0	2	25
		PVM	MATERIALS MANAGEMENT	23	0	4	27
		PVP	PURCHASING	3	0	8	11
			Subtotal for SUPPORT SERVICES	**61**	**0**	**20**	**81**

SYSTEM OPERATION

635 Employee Count by Department/Division within VP Function as of 01/31/2005

Includes Regular, Part-time, Temporary, Leaves, and Probationary Employees

Report Parameters
AsOfDate: 01/31/2005
District: P HAWAIIAN ELECTRIC COMPANY *Department:* *
VP Function: * *Division:* *

HAWAIIAN ELECTRIC COMPANY:

FUNCTION	DEPT	RA		BU	EXEC	MERIT	TOTAL
				CLASSIFICATION GROUPINGS			
		PRA	ADMINISTRATION	3	0	1	4
		PRC	COMMUNICATIONS	6	0	1	7
		PRX	CONSTRUCTION MANAGEMENT	2	0	1	3
		PRI	INSTRUMENT & CONTROL	6	0	3	9
		PRD	OPERATING DISPATCH	9	0	11	20
		PRE	OPERATING ENGINEERING	4	0	6	10
		PRR	RELAY	6	0	4	10
		PRS	SUBSTATION	30	0	4	34
			Subtotal for SYSTEM OPERATION	**66**	**0**	**31**	**97**
	VP ENERGY DELIVERY						
		P2V	VP ENERGY DELIVERY	0	1	1	2
		Total for ENERGY DELIVERY		**329**	**1**	**151**	**481**
FINANCE							
	FINANCIAL VICE PRESIDENT						
		P4V	FINANCIAL VICE PRESIDENT	0	1	2	3
	GENERAL ACCOUNTING						
		PAA	ADMINISTRATION	0	1	3	4
		PAC	CORPORATE ACCOUNTING	0	0	5	5
		PAD	COST ACCOUNTING	5	0	4	9
		PAT	PROPERTY ACCOUNTING	2	0	3	5
			Subtotal for GENERAL ACCOUNTING	**7**	**1**	**15**	**23**
	INFO TECHNOLOGY & SVCS						
		PEA	ADMINISTRATION	0	0	2	2
		PEC	CUSTOMER CARE	1	0	20	21
		PED	DEVELOPMENT SERVICES	0	0	29	29
		PEI	INFRASTRUCTURE & OPERATIONS	7	0	13	20
		PEM	MAILING SERVICES	8	0	1	9
		PEP	PROJECT & BUSINESS MGMT	0	0	7	7

635 En. .oyee Count by Department/Divisio within VP Function as of 01/31/20.

Includes Regular, Part-time, Temporary, Leaves, and Probationary Employees

Report Parameters — *AsOfDate:* 01/31/2005; *District:* P — HAWAIIAN ELECTRIC COMPANY; *VP Function:* *; *Department:* *; *Division:* *

HAWAIIAN ELECTRIC COMPANY:

FUNCTION	DEPT	RA		BU	EXEC	MERIT	TOTAL
				CLASSIFICATION GROUPINGS			
			Subtotal for INFO TECHNOLOGY & SVCS	**16**	**0**	**72**	**88**
	MANAGEMENT ACCTG & FIN SVCS						
		PKB	ADMINISTRATION	0	1	3	4
		PKC	BUDGETS	0	0	7	7
		PKM	ERP ADMINISTRATION	0	0	3	3
		PKF	FINANCIAL ANALYSIS	0	0	2	2
		PKT	TREASURY	0	0	5	5
			Subtotal for MANAGEMENT ACCTG & FIN SVCS	**0**	**1**	**20**	**21**
	RISK MANAGEMENT						
		PKI	RISK MANAGEMENT	2	0	7	9
			Total for FINANCE	**25**	**3**	**116**	**144**
GENERAL COUNSEL							
	LEGAL						
		PNL	LAND & RIGHTS OF WAY	0	0	5	5
		PNC	LEGAL	0	0	11	11
			Subtotal for LEGAL	**0**	**0**	**16**	**16**
	VP GENERAL COUNSEL						
		P5V	VP-GENERAL COUNSEL	0	1	1	2
			Total for GENERAL COUNSEL	**0**	**1**	**17**	**18**
GOVT & COMMUNITY AFFAIRS							
	EDUCATION & CONSUMER AFFAIRS						
		PQE	EDUCATION & CONSUMER AFFAIRS	1	0	5	6
	REGULATORY AFFAIRS						
		PNP	REGULATORY AFFAIRS	0	0	6	6
	VP GOVT & COMMUNITY AFFAIRS						

635 Employee Count by Department/Division within VP Function as of 01/31/2005

Includes Regular, Part-time, Temporary, Leaves, and Probationary Employees

Report Parameters

AsOfDate:	01/31/2005			
District:	P	HAWAIIAN ELECTRIC COMPANY	*Department:*	*
VP Function:	*		*Division:*	*

HAWAIIAN ELECTRIC COMPANY:

FUNCTION	DEPT	RA		BU	EXEC	MERIT	TOTAL
				CLASSIFICATION GROUPINGS			
		P3V	VP GOVT & COMMUNITY AFFAIRS	0	1	6	7
	Total for GOVT & COMMUNITY AFFAIRS			1	1	17	19
POWER SUPPLY							
	ENVIRONMENTAL						
		PJA	ADMINISTRATION	1	0	3	4
		PJB	AIR QUALITY & NOISE	0	0	6	6
		PJC	CHEMISTRY	0	0	7	7
		PJW	WATER & HAZARDOUS MATERIAL	0	0	7	7
			Subtotal for ENVIRONMENTAL	1	0	23	24
	POWER SUPPLY ENGINEERING						
		PYA	ADMINISTRATION	0	0	3	3
		PYG	POWER PLANT DRAFTING	2	0	0	2
		PYF	POWER PLANT ELECT ENGRG	0	0	9	9
		PYJ	POWER PLANT PROJECT MGT	0	0	5	5
		PYM	POWR PLANT MECH ENGRG	0	0	11	11
		PYE	PS TECHNICAL SERVICES	0	0	9	9
		PYC	SUPPORT STAFF	2	0	0	2
			Subtotal for POWER SUPPLY ENGINEERING	4	0	37	41
	POWER SUPPLY OPER & MAINT						
		PIN	HONOLULU STATION MAINTENANCE	6	0	1	7
		PIH	HONOLULU STATION OPERATIONS	14	0	5	19
		PIL	KAHE STATION MAINTENANCE	25	0	2	27
		PIK	KAHE STATION OPERATIONS	51	0	8	59
		PIM	MAINTENANCE ADMINISTRATION	1	0	1	2
		PIB	O&M ADMINISTRATION	0	0	7	7
		PIO	OPERATIONS ADMINISTRATION	0	0	3	3
		PIP	PLANNING	1	0	15	16
		PIT	TRAVELING MAINTENANCE	62	0	4	66
		PIX	WAIAU STATION MAINTENANCE	24	0	2	26

635 En., loyee Count by Department/Divisic within VP Function as of 01/31/20.

Includes Regular, Part-time, Temporary, Leaves, and Probationary Employees

Report Parameters — AsOfDate: 01/31/2005; District: P HAWAIIAN ELECTRIC COMPANY; VP Function: *; Department: *; Division: *

HAWAIIAN ELECTRIC COMPANY:

CLASSIFICATION GROUPINGS

FUNCTION	DEPT	RA		BU	EXEC	MERIT	TOTAL
		PIW	WAIAU STATION OPERATIONS	56	0	8	64
			Subtotal for POWER SUPPLY OPER & MAINT	**240**	**0**	**56**	**296**
	POWER SUPPLY SERVICES						
		PIF	FUEL RESOURCES	1	0	2	3
		PYB	GENERATION PLANNING	0	0	10	10
		PIC	POWER PURCHASE	0	0	6	6
		PIA	SERVICES ADMINISTRATION	0	0	5	5
		PYT	TRANSMISSION PLANNING	0	0	8	8
			Subtotal for POWER SUPPLY SERVICES	**1**	**0**	**31**	**32**
	VP POWER SUPPLY						
		P7V	VP POWER SUPPLY	0	1	1	2
			Total for POWER SUPPLY	**246**	**1**	**148**	**395**
PRESIDENT - HECO							
	CORPORATE AUDIT & COMPLIANCE						
		PNX	ADMINISTRATION	0	0	3	3
		PNA	INTERNAL AUDIT	0	0	3	3
		PNS	SOX COMPLIANCE	0	0	1	1
			Subtotal for CORPORATE AUDIT & COMPLIANCE	**0**	**0**	**7**	**7**
	PRESIDENT'S OFFICE						
		P9P	PRESIDENT'S OFFICE	0	2	3	5
			Total for PRESIDENT - HECO	**0**	**2**	**10**	**12**
SPECIAL PROJECTS							
	VP SPECIAL PROJECTS						
		P2W	VP SPECIAL PROJECTS	0	1	2	3
			Total for SPECIAL PROJECTS	**0**	**1**	**2**	**3**

635 Employee Count by Department/Division within VP Function as of 01/31/2005

Includes Regular, Part-time, Temporary, Leaves, and Probationary Employees

Report Parameters
AsOfDate: 01/31/2005
District: P HAWAIIAN ELECTRIC COMPANY
VP Function: *
Department: *
Division: *

HAWAIIAN ELECTRIC COMPANY:

FUNCTION	DEPT	RA	BU	EXEC	MERIT	TOTAL
			CLASSIFICATION GROUPINGS			
SR VP ENERGY SOLUTIONS						
	CUSTOMER INSTALLATION					
	PWA	ADMINISTRATION	5	0	4	9
	PWX	ENGINEERING & METER	10	0	3	13
	PWP	PLANNING & DESIGN	15	0	9	24
		Subtotal for CUSTOMER INSTALLATION	**30**	**0**	**16**	**46**
	ENERGY PROJECTS					
	PNG	ENERGY PROJECTS	0	0	8	8
	SR VP ENERGY SOLUTIONS					
	P9S	SR VP ENERGY SOLUTIONS	0	1	3	4
	TECHNOLOGY					
	PNR	TECHNOLOGY	0	0	2	2
	Total for SR VP ENERGY SOLUTIONS		**30**	**1**	**29**	**60**
SR VP OPERATIONS						
	CUSTOMER SERVICE					
	PCA	ADMINISTRATION	0	0	5	5
	PCD	CREDIT	0	0	4	4
	PCB	CUST ACCOUNTING & BILLING	4	0	2	6
	PCS	CUSTOMER ACCOUNT SERVICES	1	0	3	4
	PCH	CUSTOMER ASSISTANCE CENTER	26	0	2	28
	PCF	CUSTOMER FIELD SERVICES	0	0	5	5
	PCG	FIELD SERVICE & COLLECTIONS	23	0	2	25
	PCM	METER READING	32	0	1	33
	PCP	PAYMT PROCESS & SUPPORT CTR	13	0	1	14
		Subtotal for CUSTOMER SERVICE	**99**	**0**	**25**	**124**
	SR VP OPERATIONS					
	P8V	SR VP OPERATIONS	0	1	1	2

635 En, .oyee Count by Department/Divisio within VP Function as of 01/31/20

Includes Regular, Part-time, Temporary, Leaves, and Probationary Employees

Report Parameters

AsOfDate: 01/31/2005
District: P HAWAIIAN ELECTRIC COMPANY
VP Function: *
Department: *
Division: *

HAWAIIAN ELECTRIC COMPANY:

FUNCTION DEPT RA	BU	EXEC	MERIT	TOTAL
	CLASSIFICATION GROUPINGS			
Total for SR VP OPERATIONS	99	1	26	126
SR VP PUBLIC AFFAIRS				
GOVERNMENTAL RELATIONS				
PNI GOVERNMENTAL RELATIONS	0	0	3	3
SR VP PUBLIC AFFAIRS				
P9V SR VP PUBLIC AFFAIRS	0	1	1	2
Total for SR VP PUBLIC AFFAIRS	0	1	4	5
Total for HAWAIIAN ELECTRIC COMPANY	752	16	649	1417

TOTAL
2
3
9
14
3
6
9
2
11
15
5
19
52
2
4
10
3
17
94

[redacted]

635 Employee Count by Department/Division within VP Function as of 02/28/2005

Includes Regular, Part-time, Temporary, Leaves, and Probationary Employees

Report Parameters

AsOfDate: 02/28/2005
District: P HAWAIIAN ELECTRIC COMPANY
VP Function: *
Department: *
Division: *

HAWAIIAN ELECTRIC COMPANY:

FUNCTION	DEPT	RA	BU	EXEC	MERIT	TOTAL
			CLASSIFICATION GROUPINGS			
CORPORATE COMMUNICATIONS						
	PQC	CORPORATE COMMUNICATIONS	1	0	8	9
VP CORPORATE RELATIONS						
	P1V	VP CORPORATE RELATIONS	0	1	1	2
Total for CORPORATE RELATIONS			1	1	9	11
CUSTOMER SOLUTIONS						
CUSTOMER TECH APPLICATIONS						
	PSR	CUSTOMER TECH APPLICATIONS	1	0	8	9
ENERGY SERVICES						
	PSA	ADMINISTRATION	0	0	3	3
	PSD	CUSTOMER EFFICIENCY PROGRAM	1	0	5	6
	PSP	PRICING	0	0	5	5
		Subtotal for ENERGY SERVICES	1	0	13	14
FORECASTS & RESEARCH						
	PSM	FORECASTS & RESEARCH	0	0	10	10
INTEGRATED RESOURCE PLNG						
	PYP	INTEGRATED RESOURCE PLANNING	0	0	4	4
MARKETING SERVICES						
	PSN	MARKETING SERVICES	0	0	11	11
VP CUSTOMER SOLUTIONS						
	P1W	CUSTOMER SOLUTIONS	0	1	1	2
Total for CUSTOMER SOLUTIONS			2	1	47	50
ENERGY DELIVERY						
CONSTRUCTION & MAINTENANCE						
	PDA	ADMINISTRATION	0	0	5	5

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...isio within VP Function as of 02/28/20...

Department: *
Division: *

	CLASSIFICATION GROUPINGS			
	BU	EXEC	MERIT	TOTAL
	8	0	0	8
	3	0	2	5
	25	0	0	25
	43	0	0	43
	20	0	0	20
	0	0	2	2
	0	0	12	12
	0	0	9	9
	9	0	2	11
	23	0	0	23
	0	0	2	2
	54	0	0	54
	185	**0**	**34**	**219**
	4	0	3	7
	0	0	6	6
	5	0	12	17
	3	0	17	20
	3	0	20	23
	2	0	7	9
	17	**0**	**65**	**82**
	0	0	5	5
	12	0	1	13
	21	0	3	24
	24	0	4	28
	3	0	8	11
	60	**0**	**21**	**81**

partment/Division within VP Function as of 02/28/2005

onary Employees

WAIIAN ELECTRIC COMPANY

Department: *
Division: *

	CLASSIFICATION GROUPINGS			
	BU	EXEC	MERIT	TOTAL
	3	0	1	4
	6	0	2	8
:MENT	2	0	1	3
	6	0	3	9
	9	0	11	20
G	5	0	6	11
	6	0	4	10
	30	0	4	34
TEM OPERATION	**67**	**0**	**32**	**99**
	0	1	1	2
	329	**1**	**153**	**483**
:NT	0	1	3	4
	0	2	3	5
IG	0	0	5	5
	5	0	4	9
;	2	0	3	5
AL ACCOUNTING	**7**	**2**	**15**	**24**
	0	0	2	2
	1	0	20	21
S	0	0	29	29
:RATIONS	7	0	15	22
	8	0	1	9
GMT	0	0	7	7

635 Employee Count by Department/Division within VP Function as of 02/28/2005

Includes Regular, Part-time, Temporary, Leaves, and Probationary Employees

Report Parameters — AsOfDate: 02/28/2005; District: P — HAWAIIAN ELECTRIC COMPANY; VP Function: *; Department: *; Division: *

HAWAIIAN ELECTRIC COMPANY:

FUNCTION	DEPT	RA		BU	EXEC	MERIT	TOTAL
				CLASSIFICATION GROUPINGS			
			Subtotal for INFO TECHNOLOGY & SVCS	16	0	74	90
	MANAGEMENT ACCTG & FIN SVCS						
		PKB	ADMINISTRATION	0	1	3	4
		PKC	BUDGETS	0	0	7	7
		PKM	ERP ADMINISTRATION	0	0	3	3
		PKF	FINANCIAL ANALYSIS	0	0	3	3
		PKT	TREASURY	0	0	5	5
			Subtotal for MANAGEMENT ACCTG & FIN SVCS	0	1	21	22
	RISK MANAGEMENT						
		PKI	RISK MANAGEMENT	2	0	7	9
			Total for FINANCE	25	4	120	149
GENERAL COUNSEL							
	LEGAL						
		PNL	LAND & RIGHTS OF WAY	0	0	5	5
		PNC	LEGAL	0	0	11	11
			Subtotal for LEGAL	0	0	16	16
	VP GENERAL COUNSEL						
		P5V	VP-GENERAL COUNSEL	0	1	1	2
			Total for GENERAL COUNSEL	0	1	17	18
GOVT & COMMUNITY AFFAIRS							
	EDUCATION & CONSUMER AFFAIRS						
		PQE	EDUCATION & CONSUMER AFFAIRS	1	0	5	6
	REGULATORY AFFAIRS						
		PNP	REGULATORY AFFAIRS	0	0	5	5
	VP GOVT & COMMUNITY AFFAIRS						

635 Employee Count by Department/Division within VP Function as of 02/28/2005

Includes Regular, Part-time, Temporary, Leaves, and Probationary Employees

Report Parameters					
	AsOfDate:	02/28/2005			
	District:	P	HAWAIIAN ELECTRIC COMPANY	Department:	*
	VP Function:	*		Division:	*

HAWAIIAN ELECTRIC COMPANY:

FUNCTION	DEPT	RA		BU	EXEC	MERIT	TOTAL
				CLASSIFICATION GROUPINGS			
		P3V	VP GOVT & COMMUNITY AFFAIRS	0	1	6	7
	Total for GOVT & COMMUNITY AFFAIRS			1	1	16	18
POWER SUPPLY							
	ENVIRONMENTAL						
		PJA	ADMINISTRATION	1	0	3	4
		PJB	AIR QUALITY & NOISE	0	0	6	6
		PJC	CHEMISTRY	0	0	7	7
		PJW	WATER & HAZARDOUS MATERIAL	0	0	7	7
			Subtotal for ENVIRONMENTAL	1	0	23	24
	POWER SUPPLY ENGINEERING						
		PYA	ADMINISTRATION	0	0	3	3
		PYG	POWER PLANT DRAFTING	2	0	0	2
		PYF	POWER PLANT ELECT ENGRG	0	0	9	9
		PYJ	POWER PLANT PROJECT MGT	0	0	5	5
		PYM	POWR PLANT MECH ENGRG	0	0	9	9
		PYE	PS TECHNICAL SERVICES	0	0	9	9
		PYC	SUPPORT STAFF	2	0	0	2
			Subtotal for POWER SUPPLY ENGINEERING	4	0	35	39
	POWER SUPPLY OPER & MAINT						
		PIN	HONOLULU STATION MAINTENANCE	7	0	1	8
		PIH	HONOLULU STATION OPERATIONS	14	0	5	19
		PIL	KAHE STATION MAINTENANCE	25	0	2	27
		PIK	KAHE STATION OPERATIONS	51	0	8	59
		PIM	MAINTENANCE ADMINISTRATION	1	0	1	2
		PIB	O&M ADMINISTRATION	0	0	7	7
		PIO	OPERATIONS ADMINISTRATION	0	0	3	3
		PIP	PLANNING	1	0	15	16
		PIT	TRAVELING MAINTENANCE	61	0	4	65
		PIX	WAIAU STATION MAINTENANCE	24	0	2	26

635 Em, loyee Count by Department/Divisio within VP Function as of 02/28/20

Includes Regular, Part-time, Temporary, Leaves, and Probationary Employees

Report Parameters

AsOfDate:	*02/28/2005*				
District:	*P*	*HAWAIIAN ELECTRIC COMPANY*		*Department:*	*
VP Function:	*			*Division:*	*

HAWAIIAN ELECTRIC COMPANY:

FUNCTION	DEPT	RA		BU	EXEC	MERIT	TOTAL
				CLASSIFICATION GROUPINGS			
		PIW	WAIAU STATION OPERATIONS	56	0	8	64
			Subtotal for POWER SUPPLY OPER & MAINT	240	0	56	296
	POWER SUPPLY SERVICES						
		PIF	FUEL RESOURCES	1	0	2	3
		PYB	GENERATION PLANNING	0	0	9	9
		PIC	POWER PURCHASE	0	0	6	6
		PIA	SERVICES ADMINISTRATION	0	0	5	5
		PYT	TRANSMISSION PLANNING	0	0	8	8
			Subtotal for POWER SUPPLY SERVICES	1	0	30	31
	VP POWER SUPPLY						
		P7V	VP POWER SUPPLY	0	1	1	2
			Total for POWER SUPPLY	**246**	**1**	**145**	**392**
PRESIDENT - HECO							
	CORPORATE AUDIT & COMPLIANCE						
		PNX	ADMINISTRATION	0	0	3	3
		PNA	INTERNAL AUDIT	0	0	2	2
		PNS	SOX COMPLIANCE	0	0	3	3
			Subtotal for CORPORATE AUDIT & COMPLIANCE	0	0	8	8
	PRESIDENT'S OFFICE						
		P9P	PRESIDENT'S OFFICE	0	2	3	5
			Total for PRESIDENT - HECO	**0**	**2**	**11**	**13**
SPECIAL PROJECTS							
	VP SPECIAL PROJECTS						
		P2W	VP SPECIAL PROJECTS	0	1	3	4
			Total for SPECIAL PROJECTS	**0**	**1**	**3**	**4**

635 Employee Count by Department/Division within VP Function as of 02/28/2005

Includes Regular, Part-time, Temporary, Leaves, and Probationary Employees

Report Parameters — *AsOfDate:* 02/28/2005; *District:* P HAWAIIAN ELECTRIC COMPANY; *VP Function:* *; *Department:* *; *Division:* *

HAWAIIAN ELECTRIC COMPANY:

FUNCTION DEPT RA	BU	EXEC	MERIT	TOTAL
	CLASSIFICATION GROUPINGS			
SR VP ENERGY SOLUTIONS				
CUSTOMER INSTALLATION				
PWA ADMINISTRATION	5	0	5	10
PWX ENGINEERING & METER	10	0	3	13
PWP PLANNING & DESIGN	14	0	9	23
Subtotal for CUSTOMER INSTALLATION	**29**	**0**	**17**	**46**
ENERGY PROJECTS				
PNG ENERGY PROJECTS	0	0	8	8
SR VP ENERGY SOLUTIONS				
P9S SR VP ENERGY SOLUTIONS	0	1	3	4
TECHNOLOGY				
PNR TECHNOLOGY	0	0	2	2
Total for SR VP ENERGY SOLUTIONS	**29**	**1**	**30**	**60**
SR VP OPERATIONS				
CUSTOMER SERVICE				
PCA ADMINISTRATION	0	0	5	5
PCD CREDIT	0	0	4	4
PCB CUST ACCOUNTING & BILLING	4	0	2	6
PCS CUSTOMER ACCOUNT SERVICES	1	0	3	4
PCH CUSTOMER ASSISTANCE CENTER	26	0	2	28
PCF CUSTOMER FIELD SERVICES	0	0	5	5
PCG FIELD SERVICE & COLLECTIONS	23	0	2	25
PCM METER READING	32	0	1	33
PCP PAYMT PROCESS & SUPPORT CTR	13	0	1	14
Subtotal for CUSTOMER SERVICE	**99**	**0**	**25**	**124**
SR VP OPERATIONS				
P8V SR VP OPERATIONS	0	1	1	2

͡535 En‸r loyee Count by Department/Divisid within VP Function as of 02/28/20

ıcludes Regular, Part-time, Temporary, Leaves, and Probationary Employees

eport Parameters				
AsOfDate:	02/28/2005			
District:	P	HAWAIIAN ELECTRIC COMPANY	Department:	*
VP Function:	*		Division:	*

ıAWAIIAN ELECTRIC COMPANY:

FUNCTION	DEPT	RA	BU	EXEC	MERIT	TOTAL
			CLASSIFICATION GROUPINGS			
		Total for SR VP OPERATIONS	99	1	26	126
SR VP PUBLIC AFFAIRS						
GOVERNMENTAL RELATIONS						
	PNI	GOVERNMENTAL RELATIONS	0	0	3	3
SR VP PUBLIC AFFAIRS						
	P9V	SR VP PUBLIC AFFAIRS	0	1	1	2
		Total for SR VP PUBLIC AFFAIRS	0	1	4	5
Total for HAWAIIAN ELECTRIC COMPANY			751	17	655	1423

Productive O&M Hours

_RA	Jan 05	Feb 05
P1V	347.00	331.00
P1W	320.00	292.00
P2V	322.00	264.00
P2W	440.00	333.00
P3V	1,071.50	1,037.00
P4V	610.25	525.92
P5V	334.00	330.00
[illegible]	[illegible]	[illegible]
P7V	401.00	334.50
P8V	351.50	233.00
P9P	733.75	729.75
P9S	530.25	441.00
P9V	351.00	311.50
PAA	847.50	816.00
[illegible]	[illegible]	[illegible]
PAD	1,057.25	988.75
PAT	868.25	838.75
PBA	0.00	3.50
PBE	99.00	21.00
PBP	40.50	11.50
PBT	98.50	194.00
PBY	9.00	9.00
PBZ	82.00	47.00
PCA	751.50	784.00
PCB	1,015.00	809.00
PCD	618.00	448.00
PCF	908.75	819.00
PCG	4,120.50	3,769.92
PCH	4,358.30	4,082.05
PCM	5,297.25	4,937.25
PCP	2,040.50	1,722.00
PCS	531.00	562.00
PDA	78.50	79.50
PDC	64.50	94.00
PDD	939.67	588.75
PDF	2,438.05	2,132.61

Productive O&M Hours

_RA	Jan 05	Feb 05
PDM	-4.00	19.00
PDP	311.00	144.00
PDS	634.50	422.75
PDT	0.00	0.00
PDU	1,891.50	1,593.43
PDV	312.00	277.50
PDZ	0.00	0.00
PEA	0.00	0.00
PEC	494.00	434.50
PED	0.00	7.00
PEI	351.00	296.00
PEM	1,697.25	1,360.42
PEP	91.00	78.00
PER	0.00	0.00
PFA	718.75	590.25
PFB	1,377.87	1,287.63
PFC	144.00	135.00
PFD	1,697.00	1,605.00
PFI	498.25	423.50
PFS	1,914.00	1,602.00
PHA	383.25	338.50
PHB	2,507.00	2,435.50
PHF	718.50	641.00
PHS	3,216.33	3,052.50
PIA	526.75	431.00
PIB	552.00	486.50
PIC	740.50	645.50
PIF	147.50	138.00
PIH	2,893.50	2,387.00
PIK	8,624.75	7,705.83
PIL	3,667.00	3,439.00
PIM	207.00	262.50
PIN	689.50	863.50
PIO	123.84	143.25
PIP	2,481.25	2,150.25
PIT	9,281.50	7,923.00
PIW	8,906.61	7,843.10
PIX	2,952.00	3,188.00
PJA	622.75	610.51
PJB	344.50	345.00

Productive O&M Hours

_RA	Jan 05	Feb 05
PJC	814.25	713.75
PJW	787.75	664.25
PKB	604.97	619.67
PKC	1,029.00	1,019.08
PKF	289.00	302.50
PKI	1,196.80	1,127.38
PKM	322.83	281.10
PKS	0.00	0.00
PKT	520.25	503.75
PNA	943.25	436.50
PNC	1,516.25	1,485.25
PNG	846.17	848.00
PNI	469.00	426.00
PNL	891.25	782.00
PNP	762.50	788.50
PNR	395.00	361.00
PNS	48.00	185.25
PNX	268.50	520.00
PPA	462.50	434.50
PPI	972.00	818.00
PPW	528.00	431.00
PQC	1,371.00	1,205.75
PQE	1,095.50	868.25
PRA	21.25	0.00
PRC	628.00	496.50
PRD	3,861.00	3,294.00
PRE	1,503.58	1,160.17
PRI	1,133.00	747.50
PRR	933.00	864.50
PRS	4,425.10	2,541.49
PRX	158.00	48.00
PSA	505.00	422.00
PSD	1,083.83	867.50
PSF	0.00	0.00
PSM	1,302.50	1,280.75
PSN	1,705.00	1,383.00
PSP	756.50	627.00
PSR	1,066.50	983.50
PVA	73.00	76.75
PVF	0.00	0.00

Productive O&M Hours

_RA	Jan 05	Feb 05
PVL	1,074.00	1,022.50
PVM	159.00	84.00
PVP	1,481.50	1,077.25
PWA	175.75	91.00
PWP	432.17	324.50
PWX	1,498.27	1,497.67
PYA	145.50	127.50
PYB	726.50	633.00
PYC	141.50	102.50
PYE	1,137.50	808.00
PYF	25.00	4.00
PYG	16.00	2.00
PYJ	4.00	18.00
PYM	271.50	114.50
PYP	219.50	252.50
PYT	66.00	44.00
	144,007.57	125,876.17

Total O&M Non-Labor by RA

Exp Class	_RA	Jan 05	Feb 05
Non-Labor	P1V	$1,375.53	$1,595.86
Non-Labor	P1W	$1,152.16	$1,049.95
Non-Labor	P2V	$2,357.52	$1,193.76
Non-Labor	P2W	$901.53	$950.24
Non-Labor	P3V	$30,959.14	$24,846.68
Non-Labor	P4V	$1,123.48	$1,606.78
Non-Labor	P5V	$600.43	$713.79
Non-Labor	P6V	-$17,881.90	$23,162.80
Non-Labor	P7V	$1,862.65	$1,703.96
Non-Labor	P8V	$1,378.59	$867.97
Non-Labor	P9P	$64,009.26	$234,371.65
Non-Labor	P9S	$12,427.40	$9,098.71
Non-Labor	P9V	$13,817.11	$16,051.29
Non-Labor	PAA	$293.87	$271.34
Non-Labor	PAC	$105,793.94	$213,145.37
Non-Labor	PAD	$356.75	$731.73
Non-Labor	PAT	$0.00	$237.26
Non-Labor	PBA	$0.00	$327.38
Non-Labor	PBP	$20,191.60	$25,815.91
Non-Labor	PBT	$2,023.44	$0.00
Non-Labor	PCA	$137,379.90	$24,128.25
Non-Labor	PCB	$17,851.79	$183.39
Non-Labor	PCD	-$16,077.85	$18,526.43
Non-Labor	PCF	$1,275.62	$1,344.32
Non-Labor	PCG	$12,292.24	$14,266.86
Non-Labor	PCH	$529.32	$757.57
Non-Labor	PCM	$13,636.69	$16,316.01
Non-Labor	PCP	$182,515.39	$117,311.08
Non-Labor	PCS	$372.17	$1,042.34
Non-Labor	PDA	$173,454.95	$118,482.89
Non-Labor	PDC	-$36,580.62	-$26,521.78
Non-Labor	PDD	$0.00	$24.00
Non-Labor	PDF	$20,414.30	$19,074.29
Non-Labor	PDH	$1,093.75	$455.03
Non-Labor	PDK	$0.00	$9.99
Non-Labor	PDL	$123.80	-$1,379.66
Non-Labor	PDM	$300.00	$0.00
Non-Labor	PDP	$30,752.81	$81,772.15

Total O&M Non-Labor by RA

Exp Class	_RA	Jan 05	Feb 05
Non-Labor	PDT	$11,908.25	$15,056.66
Non-Labor	PDU	$25,932.56	$64,501.45
Non-Labor	PDV	$46,381.60	$73,731.95
Non-Labor	PEA	$1,201.14	$4,291.27
Non-Labor	PEC	$5,058.03	$2,000.30
Non-Labor	PEI	$0.00	$266.24
Non-Labor	PEM	$2,615.04	$5,914.03
Non-Labor	PEP	$16,351.50	$17,007.10
Non-Labor	PEZ	$580,814.40	$570,183.64
Non-Labor	PFA	$620.26	$2,065.02
Non-Labor	PFB	$1,820,505.10	$1,794,279.12
Non-Labor	PFD	$214.47	$11,644.95
Non-Labor	PFI	$15,744.02	$10,522.82
Non-Labor	PFS	$40,904.50	$44,249.85
Non-Labor	PHA	$50,228.92	$124,935.72
Non-Labor	PHB	$29,775.83	$57,039.11
Non-Labor	PHF	$34,121.48	$45,557.50
Non-Labor	PHS	$161,092.01	$109,683.61
Non-Labor	PIA	$1,937.23	$3,028.21
Non-Labor	PIB	$1,766.33	$4,314.40
Non-Labor	PIC	$136.73	$1,887.23
Non-Labor	PIH	$8,242.40	$10,786.85
Non-Labor	PIK	$125,681.56	$102,057.55
Non-Labor	PIL	$782,085.02	$246,638.41
Non-Labor	PIM	$12,098.06	$5,561.43
Non-Labor	PIN	$1,039.11	$45,895.82
Non-Labor	PIO	$855.87	$1,013.22
Non-Labor	PIP	$969.01	$1,140.99
Non-Labor	PIT	$617,320.16	$385,815.92
Non-Labor	PIW	$37,351.00	$29,516.29
Non-Labor	PIX	$492,092.79	$294,110.40
Non-Labor	PJA	$1,631.32	$4,544.56
Non-Labor	PJB	$97,847.12	$89,672.87
Non-Labor	PJC	$11,014.64	$6,387.93
Non-Labor	PJW	$4,380.40	$5,045.35
Non-Labor	PKB	$25.12	$196.95
Non-Labor	PKC	$561.07	$19,273.79
Non-Labor	PKI	$332,091.86	$283,231.99

Total O&M Non-Labor by RA

Exp Class	_RA	Jan 05	Feb 05
Non-Labor	PKM	$45,652.96	$45,672.49
Non-Labor	PKT	$15,840.18	$28,400.74
Non-Labor	PNA	$237.55	$1,710.79
Non-Labor	PNC	$1,125.91	$4,698.88
Non-Labor	PNG	-$6,103.74	$2,092.64
Non-Labor	PNI	$1,668.52	$1,009.61
Non-Labor	PNL	$17,264.88	$22,237.65
Non-Labor	PNP	$711.06	$18,763.61
Non-Labor	PNR	$137,173.33	$130,606.99
Non-Labor	PPA	$693.21	$3,709.33
Non-Labor	PPI	$25.12	$895.98
Non-Labor	PPW	$115,592.74	$173,023.45
Non-Labor	PQC	$17,509.52	$23,655.07
Non-Labor	PQE	$9,958.24	$649.66
Non-Labor	PRA	$1,658.87	$566.80
Non-Labor	PRC	$3,946.60	$8,955.88
Non-Labor	PRD	$11,029.97	$26,074.58
Non-Labor	PRE	$18,478.81	$18,466.49
Non-Labor	PRI	$14,179.97	$6,047.53
Non-Labor	PRR	$5,733.34	$604.21
Non-Labor	PRS	$63,118.26	$25,908.48
Non-Labor	PRX	$0.00	$4,910.82
Non-Labor	PSA	$117.91	$167.10
Non-Labor	PSD	$571,952.63	$487,346.79
Non-Labor	PSM	$7,688.28	$8,688.48
Non-Labor	PSN	-$15,069.72	$5,938.20
Non-Labor	PSP	$1,055.34	$1,915.98
Non-Labor	PSR	$2,115.86	$1,687.97
Non-Labor	PVA	$2,114.52	$1,754.22
Non-Labor	PVL	$11,754.88	$13,682.06
Non-Labor	PVM	$9,844.68	$6,995.44
Non-Labor	PVP	$7,195.33	$1,108.14
Non-Labor	PWA	$0.00	$102.92
Non-Labor	PWP	$6,075.14	-$33,538.55
Non-Labor	PWX	$6,869.01	$8,884.18
Non-Labor	PYA	$100,815.41	$102,980.68
Non-Labor	PYB	$10.00	$5,742.92
Non-Labor	PYE	$325.00	$68.00

Total O&M Non-Labor by RA

Exp Class	_RA	Jan 05	Feb 05
Non-Labor	PYF	$9.00	$0.00
Non-Labor	PYM	$0.00	$19,359.25
Non-Labor	PYP	$3,099.07	$4,652.90
		$7,346,140.31	$6,622,784.45

CA-IR-332

Ref: HECO WP-303, page 2.

For each line item of Miscellaneous Revenues on page 2 of this workpaper, please provide the following information:

a. Please identify the HPUC Decision, if any, that is associated with the underlying transactions (for example, the gain amortization amounts and rentals) as applicable and state the original amount, amortization period and beginning/termination date for such amortization.

b. Provide a monthly breakdown of actual recorded miscellaneous revenues in each month of 2004, by sub-account and category/type of miscellaneous revenue, indicating how such recorded amounts compare with the amounts set forth in this Workpaper.

c. State whether any recorded miscellaneous revenues on HECO's books in 2004 (see part b, above) were excluded in preparing the Company's test year projections and explain the basis for such exclusion.

d. State whether HECO has experienced any gains or losses from the disposition of property since the last general rate case and provide a description of the property transaction, as well as detailed calculations associated with the gain/loss that was realized.

e. If your response to part d is affirmative, please reference all HPUC applications and actions associated with the described transaction(s).

HECO Response:

a. See page 2 of this response. Note that the test year estimate for the amortization for Iolani Court will be revised as identified in HECO's response to CA-IR-372.

b. See page 3 of this response.

c. Yes. Refer to page 3 of this response. Amortization of gains for Wilder Sub, Makiki Sub, and Ft. Shafter Flats were excluded from the test year 2005 because their amortization periods terminated in 2004.

d. Yes. See page 4 of this response.

e. Each transaction's respective Docket reference and Decision and Order are listed on page 4 of this response.

Hawaiian Electric Company, Inc.
Gains From Disposition of Property
Gains Currently Being Amortized

Property	Docket No.	PUC D&O	Net Gain	Amortization Period	Amort. Months
Emma Sub	02-0098	19839	$1,399,868.22	Feb-05 - Jan-10	60
Kuliouou Sub	98-0314	16935	$199,639.43	Aug-04 - Jul-09	60
Iolani Court	98-0170	16833	$121,909.26	Dec-04 - Nov-09	60
Iolani Court	98-0170	16833	$109,835.26	Jan-04 - Dec-08	60
Lilipuna	98-0314	16935	$103,847.82	Apr-00 - Mar-05	60
Iolani Court	98-0170	16833	$51,467.84	Jul-02 - Jun-07	60
Iolani Court	98-0170	16833	$50,023.64	Jan-05 - Dec-09	60

Property	Docket No.	PUC D&O	Lease Premium	Amortization Period	Amort. Months
Iolani Court	98-0170	16833	$1,119.91	Jul-02 - Jun-07	60
Iolani Court	98-0170	16833	$903.11	Jan-04 - Dec-08	60
Iolani Court	98-0170	16833	$770.67	Dec-04 - Nov-09	60
Iolani Court	98-0170	16833	$758.59	Jan-05 - Dec-09	60

Hawaiian Electric Company, Inc.
Other Operating Revenues
Miscellaneous Revenues
2004 Actuals vs. 2005 Test Year Forecast
In $000s

	Test Year	Actual	Recorded											
	2005	2004	Jan-04	Feb-04	Mar-04	Apr-04	May-04	Jun-04	Jul-04	Aug-04	Sep-04	Oct-04	Nov-04	Dec-04
Amort Gain - Iolani Court	$32.3 [1]	$59.7	$9.4	$9.4	$9.4	$5.3	$3.9	$3.1	$3.1	$3.1	$3.1	$2.7	$2.7	$4.7
Amort Gain - Lilipuna	$4.8	$20.8	$1.7	$1.7	$1.7	$1.7	$1.7	$1.7	$1.7	$1.7	$1.7	$1.7	$1.7	$1.7
Amort Gain - Emma Sub	$256.3	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Amort Gain - Kuliouou Sub	$39.6	$16.5	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$3.3	$3.3	$3.3	$3.3	$3.3
Amort Gain - Wilder Sub	$0.0	$13.2	$2.2	$2.2	$2.2	$2.2	$2.2	$2.2	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Amort Gain - Makiki Sub	$0.0	$76.6	$9.6	$9.6	$9.6	$9.6	$9.6	$9.6	$9.6	$9.6	$0.0	$0.0	$0.0	$0.0
Amort Gain - Ft. Shafter Flats	$0.0	$47.4	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$47.4
Temporary Facilities	-$20.0	-$263.9	-$22.0	-$13.2	-$33.8	-$56.6	-$14.0	-$42.5	$0.0	-$17.6	-$16.1	-$14.8	-$12.2	-$21.1
Rent From Electric Prop.	$12.6	$11.0	$0.9	$0.9	$0.4	$0.9	$0.9	$0.9	$0.9	$0.9	$0.9	$1.1	$1.1	$1.1
Paid Parking (net)	$216.0	$172.8	$13.4	$13.2	$13.1	$13.7	$14.0	$14.6	$18.9	$11.6	$13.1	$16.3	$15.6	$15.3
Amort Lease Prem. & Lease Rent	$221.4	$354.3	$24.2	$6.8	$39.4	$28.9	$23.9	$26.6	$30.8	$46.7	$27.3	$24.5	$40.8	$34.6
Telecom Rent (net)	$234.9	$237.2	$42.2	$22.6	$12.8	$11.2	$11.2	$38.8	$14.2	$15.9	$11.2	$27.7	$11.2	$18.1
Other	$13.0	$42.2	$0.0	$6.8	$0.0	$0.0	$23.3	$0.0	$2.8	$0.0	$3.1	$0.0	$6.3	$0.0
Total Miscellaneous Revenues	$1,010.9	$787.9												

[1] The revised amortization for Iolani Court is $66.6, as described in HECO's response to CA-IR-372. This revised estimate will be included in HECO's next determination of revenue requirements.

Hawaiian Electric Company, Inc.
Gains From Disposition of Property Since Docket No. 7766
Where Amortization of Gains Are Completed

Property	Sold	Docket No.	PUC D&O	Sales Price	Property Cost	Expenses of Sale	Net Gain[1]	Amortization Period	Amort. Months
Makiki Sub	Aug-99	98-0314	16935	$595,000.00	$6,703.00	$14,172.00	$574,125.00	Sep-99 - Aug-04	60
Wilder Sub	Jun-99	98-0314	16935	$525,000.00	$335,137.00	$8,932.00	$180,931.00	Jul-99 - Jun-04	60
Iolani Court	Mar-99	98-0170	16833	$98,000.00	$541.95	$3,870.67	$93,587.38	Apr-99 - Mar-04	60
Iolani Court	Apr-99	98-0170	16833	$91,543.00	$7,912.76	$4,000.33	$79,629.91	May-99 - Apr-04	60
Iolani Court	Mar-99	98-0170	16833	$60,384.00	$5,219.46	$2,567.96	$52,596.58	Apr-99 - Mar-04	60
Iolani Court	Mar-99	98-0170	16833	$60,384.00	$5,219.46	$2,616.49	$52,548.05	Apr-99 - Mar-04	60
Iolani Court	May-99	98-0170	16833	$54,000.00	$361.30	$2,058.19	$51,580.51	Jun-99 - May-04	60
Iolani Court	Mar-99	98-0170	16833	$55,568.00	$4,803.12	$2,345.72	$48,419.16	Apr-99 - Mar-04	60
Ft. Shafter Flats	Dec-04	02-0202	19966	$65,500.00	$15,020.28	$3,092.18	$47,387.54	Dec-04	1
Iolani Court	Sep-99	98-0170	16833	$26,234.00	$2,267.57	$997.87	$22,968.56	Oct-99 - Sep-04	60

[1] Includes both regulated and non-regulated portions.

CA-IR-332
DOCKET NO. 04-0113
PAGE 4 OF 4

CA-IR-333

Ref: HECO-304 Residential Revenue at Proposed Rates.

HECO-304 at page 1 reflects negative $116,500 revenue at proposed rates captioned as "Miscellaneous" that is attributed to Schedule E, Minimum Bill Adjustments, Apartment House Discount and Residential TOU (per footnote).

a. Please provide a detailed breakdown of this amount by element, indicating which pages of HECO-WP-304 provide supporting calculations for each element.

b. Explain why proposed rate changes have the effect of significantly reducing the negative value of these tariff elements.

HECO Response:

a. The detailed breakdown by element of Schedule R revenue adjustments at proposed rates can be found on HECO-2218, with supporting calculations on HECO-WP-304, page 3, 4, 7, and 8. The calculation of the Schedule E discount and its allocation to different rate schedules at proposed rates are shown on pages 2-3 of this response.

b. Please refer to the detail of Schedule R revenue adjustments on HECO-2218. The Schedule E adjustment at present rates is calculated at Schedule R rates and attributed entirely to Schedule R. At proposed rates, the Schedule E adjustment is allocated to the various rate schedules (based on the calculation provided on page 2 of this response), as reflected in HECO-2218 through HECO-2225. HECO has allocated the Schedule E adjustment to all rate classes in prior rate cases and it has been approved by the Commission. See also HECO's response to CA-IR-360, part (d).

HAWAIIAN ELECTRIC COMPANY, INC.
Docket No. 04-0113, Test-Year 2005

ALLOCATION OF SCHEDULE E ADJUSTMENT

Rate Schedule	Allocation Factor[1]	Sch. E Adj. $1000s
R	44.99%	(392.4)
G	6.55%	(57.1)
J	21.18%	(184.9)
H	0.63%	(5.5)
PS	7.80%	(68.0)
PP	17.20%	(150.0)
PT	1.03%	(9.0)
F	0.62%	(5.4)
Total	100.00%	(872.3)

[1] Based on O&M Labor % From Cost of Service Study.

HAWAIIAN ELECTRIC COMPANY, INC.
Docket No. 04-0113, Test-Year 2005
SCHEDULE R - RESIDENTIAL SERVICE
CALCULATION OF SCHEDULE E ADJUSTMENT

ALL SINGLE PHASE

ESTIMATE OF TEST-YEAR REVENUE ADJUSTMENTS
FOR EMPLOYEE SERVICE

	RECORDED	FORECAST
MWH SALES:		
0-825 KWH	7,143	7,451
>825 KWH	12,809	13,362
TOTAL	19,953	20,813
NUMBER OF BILLS:		
0-825 KWH	13,292	13,434
>825 KWH	10,263	10,373
TOTAL	23,555	23,807

		PRESENT RATES		PROPOSED RATES	
EMPLOYEE DISCOUNT 0-825 KWH	UNITS BILLED (MWH)	UNIT PRICE $/KWH	REVENUES $1000s	UNIT PRICE $/KWH	REVENUES $1000s
ENERGY CHARGE	7451	11.2954	841.6	14.8599	1,107.2
FUEL OIL ADJUSTMENT:	7451	2.586	192.7	0.000	0.0
DSM ADJUSTMENT:	7451	0.0000	0.0	0.0000	0.0
SUBTOTAL			1,034.3		1,107.2
	BILLS				
CUSTOMER CHARGE	13434	7.00	94.0	10.00	134.3
TOTAL			1,128.3		1,241.5
-1/3 EMPLOYEE ADJUSTMENT			(376.1)		(413.8)

		PRESENT RATES		PROPOSED RATES	
EMPLOYEE DISCOUNT >825 KWH LIMITED to 825 KWH	UNITS BILLED (MWH)	UNIT PRICE $/KWH	REVENUES $1000s	UNIT PRICE $/KWH	REVENUES $1000s
ENERGY CHARGE	8558	11.2954	966.7	14.8599	1,271.7
FUEL OIL ADJUSTMENT:	8558	2.586	221.3	0.000	0.0
DSM ADJUSTMENT:	8558	0.0000	0.0	0.0000	0.0
SUBTOTAL			1,188.0		1,271.7
	BILLS				
CUSTOMER CHARGE	10373	7.00	72.6	10.00	103.7
TOTAL			1,260.6		1,375.4
-1/3 EMPLOYEE ADJUSTMENT			(420.2)		(458.5)
TOTAL EMPLOYEE ADJ:			(796.3)		(872.3)

CA-IR-334

<u>Ref: HECO-1314 (Administrative Expenses Transferred)</u>.

Please provide supporting documentation for the following items appearing on HECO-1314:

a. Cost Pool-Labor of $1,453,000.

b. Cost Pool-Nonlabor of $11,083,000.

c. Cost Base-Capital Labor Hours of 452,000.

d. Cost Base-Clearings to Capital of 210,000 hours.

<u>HECO Response:</u>

a. The requested information is provided on pages 2 to 5 of this response.

b. The requested information is provided on page 6 of this response.

c. The requested information is provided on page 7 of this response.

d. The requested information is provided on pages 8 to 11 of this response.

2005 Admin Transfer Labor:

Position	RA	Labor Class	A Std Labor Rate	B Prod Hours		C = A × B Total Dollars
A/P and Disb Clerk	AD	BUOC	23.07	1,094	6,414 A	25,239
Accounting Clerk II	AD	BUOC	23.07	863		19,909
Accounting Clerk II	AD	BUOC	23.07	863		19,909
Accounting Clerk III	AD	BUOC	23.07	863		19,909
Accounting Clerk III	AD	BUOC	23.07	1,868		43,095
Invoice Payment Clerk	AD	BUOC	23.07	863		19,909
Job Accounting Clerk	AT	BUOC	23.07	1,776	3,592 B	40,972
Plant Accounting Clerk	AT	BUOC	23.07	1,816		41,895
Purchasing Clerk	VP	BUOC	23.07	432	1,728 C	9,966
Purchasing Clerk	VP	BUOC	23.07	432		9,966
Purchasing Clerk	VP	BUOC	23.07	432		9,966
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]		[illegible]
Asst Plant Accountant	AT	I	23.72	1,816	D	43,076
Land Assist	NL	I	23.72	1,864	E	44,214
Work Staff & Dev Coord	FI	I	23.72	1,739	3,478 F	41,237
Work Staff & Dev Coord	FI	I	23.72	1,739		41,237
Buyer	VP	TC	30.67	2,774	11,096 G	85,079
Buyer	VP	TC	30.67	2,774		85,079
Buyer	VP	TC	30.67	2,774		85,079
Buyer	VP	TC	30.67	2,774		85,079
Lead Func Admin - Proj Con	AA	TC	30.67	1,824	H	55,942
Land Agent	NL	TC	30.67	1,984	7,936 I	60,842
Land Agent	NL	TC	30.67	1,984		60,842
Land Agent	NL	TC	30.67	1,984		60,842
Land Agent	NL	TC	30.67	1,984		60,842
Property Accountant	AT	TC	30.67	1,712	3,648 J	52,507
Property Accountant (2005 n	AT	TC	30.67	1,936		59,377
Work Staff & Dev Consult	FD	TC	30.67	1,701	8,505 K	52,170
Work Staff & Dev Consult	FD	TC	30.67	1,701		52,170
Work Staff & Dev Consult	FD	TC	30.67	1,701		52,170
Work Staff & Dev Consult	FD	TC	30.67	1,701		52,170
Work Staff & Dev Consult	FD	TC	30.67	1,701		52,170
Total				51,899		1,452,823

Total hours 51,899

Bud08-Lbr Hrs by Acct (CA-IR-3...

NARUC	NARUC Descr	_RA	_Act	Activity	_EE	_LbrClass	FY05	
920	A&G EXP-LABR	PAA	818	Maint G/L & Stat Info	150	__TC	1,704	
920	A&G EXP-LABR	PAA	835	Fin Rpts/StatInfo-Int	150	__TC	120	
920	A&G EXP-LABR	PAA				__TC	1,824	H
920	A&G EXP-LABR	PAD	789	Attend Training	150	__BUOC	40	
920	A&G EXP-LABR	PAD	840	Adm Oth Procur Pgm-Misc	150	__BUOC	480	
920	A&G EXP-LABR	PAD	843	Proc Invoices Oth Pmt	150	__BUOC	5,894	
920	A&G EXP-LABR	PAD				__BUOC	6,414	A
920	A&G EXP-LABR	PAT	777	Process Payroll	150	__BUOC	96	
920	A&G EXP-LABR	PAT	817	Maint Fixed Asset Rcds	150	__BUOC	2,584	
920	A&G EXP-LABR	PAT	818	Maint G/L & Stat Info	150	__BUOC	896	
920	A&G EXP-LABR	PAT	836	Fin Rpts/StatInfo-Ext	150	__BUOC	16	
920	A&G EXP-LABR	PAT				__BUOC	3,592	B
920	A&G EXP-LABR	PAT	817	Maint Fixed Asset Rcds	150	__I	1,686	
920	A&G EXP-LABR	PAT	818	Maint G/L & Stat Info	150	__I	96	
920	A&G EXP-LABR	PAT	819	Adm Tax Return & Reports	150	__I	20	
920	A&G EXP-LABR	PAT	836	Fin Rpts/StatInfo-Ext	150	__I	14	
920	A&G EXP-LABR	PAT				__I	1,816	D
920	A&G EXP-LABR	PAT	735	Rate Case Filings	150	__TC	80	
920	A&G EXP-LABR	PAT	761	Audits-External	150	__TC	50	
920	A&G EXP-LABR	PAT	817	Maint Fixed Asset Rcds	150	__TC	1,010	
920	A&G EXP-LABR	PAT	818	Maint G/L & Stat Info	150	__TC	272	
920	A&G EXP-LABR	PAT	819	Adm Tax Return & Reports	150	__TC	260	
920	A&G EXP-LABR	PAT	836	Fin Rpts/StatInfo-Ext	150	__TC	1,976	
920	A&G EXP-LABR	PAT				__TC	3,648	J
920	A&G EXP-LABR	PFD	720	Improve Bus Processes	150	__TC	75	
920	A&G EXP-LABR	PFD	721	Dev Meas & Anlz Perf	150	__TC	366	
920	A&G EXP-LABR	PFD	722	Org Dev Strat	150	__TC	1,175	
920	A&G EXP-LABR	PFD	749	Maint Rel-Ind Assoc	150	__TC	80	
920	A&G EXP-LABR	PFD	765	Empl Pol Prac Proc	150	__TC	1,925	
920	A&G EXP-LABR	PFD	767	Recruit PolPracProc	150	__TC	4,864	
920	A&G EXP-LABR	PFD	797	Attend Safety Training	150	__TC	20	

Bud08-Lbr Hrs by Acct (CA-IR-3...

NARUC	NARUC Descr	_RA	_Act	Activity	_EE	_LbrClass	FY05	
920	A&G EXP-LABR	PFD				__TC	8,505	K
920	A&G EXP-LABR	PFI	701	Dev & Mg Forecasts	150	__I	395	
920	A&G EXP-LABR	PFI	720	Improve Bus Processes	150	__I	304	
920	A&G EXP-LABR	PFI	721	Dev Meas & Anlz Perf	150	__I	143	
920	A&G EXP-LABR	PFI	722	Org Dev Strat	150	__I	986	
920	A&G EXP-LABR	PFI	765	Empl Pol Prac Proc	150	__I	625	
920	A&G EXP-LABR	PFI	766	Maint Employee Recds	150	__I	415	
920	A&G EXP-LABR	PFI	767	Recruit PolPracProc	150	__I	3,408	
920	A&G EXP-LABR	PFI	777	Process Payroll	150	__I	60	
920	A&G EXP-LABR	PFI	785	Plan Emp Trng & Dev	150	__I	393	
920	A&G EXP-LABR	PFI	789	Attend Training	150	__I	152	
920	A&G EXP-LABR	PFI	797	Attend Safety Training	150	__I	4	
920	A&G EXP-LABR	PFI	807	Co-wide Empl Commun	150	__I	69	
920	A&G EXP-LABR	PFI				__I	6,954 = 4 positions	
							3477 = 2 positions	F
920	A&G EXP-LABR	PNL	701	Dev & Mg Forecasts	150	__I	19	
920	A&G EXP-LABR	PNL	722	Org Dev Strat	150	__I	48	
920	A&G EXP-LABR	PNL	745	Maint Rel-Leg & Govt Ag	150	__I	18	
920	A&G EXP-LABR	PNL	777	Process Payroll	150	__I	36	
920	A&G EXP-LABR	PNL	807	Co-wide Empl Commun	150	__I	36	
920	A&G EXP-LABR	PNL	842	Order Mat Eq Sup & Svcs	150	__I	24	
920	A&G EXP-LABR	PNL	843	Proc Invoices Oth Pmt	150	__I	60	
920	A&G EXP-LABR	PNL	926	Manage Property	150	__I	189	
920	A&G EXP-LABR	PNL	928	Process Easements	150	__I	1,434	
920	A&G EXP-LABR	PNL				__I	1,864	E
920	A&G EXP-LABR	PNL	701	Dev & Mg Forecasts	150	__TC	180	
920	A&G EXP-LABR	PNL	745	Maint Rel-Leg & Govt Ag	150	__TC	75	
920	A&G EXP-LABR	PNL	807	Co-wide Empl Commun	150	__TC	540	
920	A&G EXP-LABR	PNL	926	Manage Property	150	__TC	2,520	
920	A&G EXP-LABR	PNL	928	Process Easements	150	__TC	4,620	
920	A&G EXP-LABR	PNL				__TC	7,935	I

Bud08-Lbr Hrs by Acct

NARUC	NARUC Descr	_RA	_Act	Activity	_EE	_LbrClass	FY05	
920	A&G EXP-LABR	PVP	789	Attend Training	150	__BUOC	48	
920	A&G EXP-LABR	PVP	797	Attend Safety Training	150	__BUOC	4	
920	A&G EXP-LABR	PVP	843	Proc Invoices Oth Pmt	150	__BUOC	1,676	
920	A&G EXP-LABR	PVP				__BUOC	1,728	C
920	A&G EXP-LABR	PVP	789	Attend Training	150	__TC	564	
920	A&G EXP-LABR	PVP	797	Attend Safety Training	150	__TC	14	
920	A&G EXP-LABR	PVP	840	Adm Oth Procur Pgm-Misc	150	__TC	564	
920	A&G EXP-LABR	PVP	842	Order Mat Eq Sup & Svcs	150	__TC	9,534	
920	A&G EXP-LABR	PVP	844	Prep Contr-Svcs & Mat	150	__TC	420	
920	A&G EXP-LABR	PVP				__TC	11,096	G

		$000	
Direct non-labor, NARUC 921		12,297	HECO-WP-101(G) page 968
Adjustment to budget for ITS expense elements 451/462 was not included in Administrative Expenses Transferred calculation		(91)	
Naruc 921 Nonlabor on-costs			
Stores		84	
Energy Delivery		119	
Power Supply		6	
Subtotal		12,415	
Less: Items excluded from 2005 test year NARUC 921			
HEI Incentive Compensation		285	HECO-1304
Admin & Genl - Other Awards (Account 921):			
Service Awards	38		
Key Contributor Award	185		
Team Award	93		
Subtotal		316	HECO-1304[1]
e-business		284	Excluded erroneously, see HECO-1314 page 2
IRP Amortization		447	HECO T-13, page 16, line 13
Subtotal		1,332	
Cost Pool-Nonlabor-Acct. 921.00		11,083	

[1] $316k + $27k Recognition Awards = $343k per HECO-1304
$27k Recognition Awards should have been excluded; see HECO-1314, page 2 for correction

Bud28-Total Capital hours

NARUC	NARUC Descr	Exp Class	Exp Element	FY05
107	CWIP	Labor	Labor Cost	406,481.07
107	CWIP	Labor		406,481.07
108	ACCUM PROV DEPR	Labor	Labor Cost	45,127.75
108	ACCUM PROV DEPR	Labor		45,127.75
				451,608.82

2005

	A Capital % of Base	From Pages 9-10	B Labor Hours in Clearing (From Page 11)	C = A × B Labor Hours in Capital
Benefits	15%	I	18	3
Customer	100%	W	41	41
Stores	77%	F	64	49
Vehicles	1%	C	56	0
PS	12%	T	77	9
ED	48%	P	226	108
ISD	0%	L	151	0
			Total	210

***EE on-Costs**

EE	Exp Element	Acct Grp Descr	FY05	
301	Vehicles	Capital	$32,632.75	A
		Charges to Clearing	$5,220,379.53	
		Deferred Debit	$180.00	C = A/B = 1%
		O&M	$1,078,072.23	
		Oth Income Statement	$29,375.04	
			$6,360,639.55	B
401	Stores	Billable	$49,749.08	
		Capital	$3,683,963.91	D
		Charges to Clearing	$132,804.67	
		Deferred Debit	$33,723.00	
		Fuel & Purch Pwr	$3,046.15	F = D/E = 77%
		O&M	$874,576.70	
		Operating Revenues	$208.32	
		Oth Income Statement	$26,279.51	
			$4,804,351.35	E
422	Employee Benefits	Billable	$757,443.87	
		Capital	$2,847,822.66	G
		Charges to Clearing	$3,909,455.99	
		Deferred Debit	$102,971.60	
		Fuel & Purch Pwr	$0.00	I = G/H = 15%
		O&M	$11,538,536.42	
		Operating Revenues	$2,209.80	
		Oth Income Statement	$30,744.92	
			$19,189,185.27	H
451	IS Exp-Production	Billable	$450,721.20	
		Capital	$5,405.82	J
		Charges to Clearing	$3,136,416.00	
		Deferred Debit	$300,118.81	
		Fuel & Purch Pwr	$17,688.05	L = J/K = 0%
		O&M	$8,173,669.17	
		Oth Income Statement	$253,340.94	
			$12,337,360.00	K

***Check VB-OHs detail hrs**

_EE	Exp Element	Acct Grp Descr	FY05	
404	Energy Delivery	Billable	22,533.89	
404	Energy Delivery	Capital	325,701.72	M
404	Energy Delivery	Deferred Debit	2,996.00	N
404	Energy Delivery	O&M	327,933.27	
404	Energy Delivery	Oth Income Statement	492.0	
404			679,656.88	O
405	Power Supply	Billable	10,795.22	
405	Power Supply	Capital	80,515.89	Q
405	Power Supply	Fuel & Purch Pwr	5,184	R
405	Power Supply	O&M	636,478.98	
405			732,974.09	S
407	Cust Installations	Capital	24,291.06	U
407			24,291.06	V

P = (M+N)/O = 48%

T = (Q+R)/S = 12%

W = U/V = 100%

Bud01-Chgs to Clrgs - Hours

GL INT NARUC	NARUC Descr	Inter Code Descr	FY05
163	STORES EXP		64,350.0
184050	CLRNG ACCTS	CLR-POWER SUPPLY	76,848.11
184060	CLRNG ACCTS	CLR-ENERGY DELIVERY	226,438.21
184080	CLRNG ACCTS	CLRNG-CUST INSTALL	41,087.04
184110	CLRNG ACCTS	CLRNG-VEHICLES	56,384
184120	CLRNG ACCTS	CLRNG-ISD	150,555.00
926000	EE PENSION/BENEFIT	EMP PENSION/BENEFITS	15,915.00
926010	EE PENSION/BENEFIT	EE BEN-FLEX CREDITS	2,057

17,972

CA-IR-335

Ref: T-15, pages 43-44 & HECO-1315 (Employee Benefits Transferred).

HECO-1315 provides the calculation of the 2005 test year forecast for employee benefits [illegible]

transferred (Account 926020), based on an employee benefit rate per hour. [Note: If the information requested below has been previously provided in response to CA-IR-2 or another interrogatory, please provide a pinpoint reference to the responsive data.] Please provide the following:

a. Please provide the summary report supporting the total Company productive hours of 3,022,000 set forth on HECO-1315.

b. Referring to item (a) above, please provide a breakdown of the productive hours between the following general categories: O&M expense accounts, capital accounts, affiliate billings, other non-expense accounts.

c. In general terms, does the distribution of employee benefit costs follow the distribution of labor costs? Please explain and provide a copy of any supporting documentation.

Bud23-Total labor hours

Exp Class	Exp Element	Acct Grp Descr	FY05
Labor	Labor Cost	Billable	119,282.62
		Capital	451,608.82
		Charges to Clearing	615,662.36
		Deferred Debit	16,216.00
		Fuel & Purch Pwr	5,344.08
		O&M	1,811,748.53
		Operating Revenues	348
		Oth Income Statement	4,841.72
			3,025,052.13
			3,025,052.13

Less: Police hrs 3132.60 from page 3

Total Company productive hours 3,021,919.53

Bud11-Lbr Hrs for Lbr Clss POLI...

_RA	_LbrClass	Labor Class	Acct Grp Descr	FY05
PZP	__POLICE	Police work	Capital	3,132.60
PZP				3,132.60
				3,132.60

to page 2

***EE on-Costs**

_EE	Acct Grp Descr	Labels	FY05
422	Billable	Units	119,282.50
		Rates	$7.99
		Amounts	$953,067.17
422	Capital	Units	448,476.01
		Rates	$7.99
		Amounts	$3,583,323.32
422	Charges to Clearing	Units	615,662.36
		Rates	$7.99
		Amounts	$4,919,142.26
422	Deferred Debit	Units	16,216.00
		Rates	$7.99
		Amounts	$129,565.84
422	Fuel & Purch Pwr	Units	5,344.08
		Rates	$7.99
		Amounts	$42,699.20
422	O&M	Units	1,811,748.27
		Rates	$7.99
		Amounts	$14,475,868.68
422	Operating Revenues	Units	348
		Rates	$7.99
		Amounts	$2,780.52
422	Oth Income Statement	Units	4,841.72
		Rates	$7.99
		Amounts	$38,685.34
422		Units	3,021,918.94
		Rates	$7.99
		Amounts	$24,145,132.33

CA-IR-336

Ref: T-15, page Ref: 4 & HECO-1502 (Pension Costs).

HECO-1502 provides a multi-year comparison of Administrative and General Expenses charged to Account 926. Please provide the following with regard to the qualified pension plan:

a. Please identify and describe the impact of revisions to key assumptions, actual returns, plan amendments or other key factors causing the dramatic change in NPPC from a negative \$20.5 million in 2001 to positive levels in 2003 actual and 2005 forecast.

b. Please explain and reconcile why the 2004 forecast is a negative NPPC amount in relation to positive amounts for the 2003 actual and 2005 forecast.

HECO Response:

a. Between 2001 and 2005, 1) the discount rate was decreased from 7.5% to 6.0%, 2) the long-term asset return assumption was decreased from 10% to 9%, 3) the mortality table was changed from the GAM71 male table (set back two years for males and eight years for females) to the GAM83 table (separate rates for males and females), and 4) the plan experienced asset losses exceeding \$230 million. All of these factors contributed to the significant increase in NPPC between 2001 and 2005.

b. For 2003, the plan experienced an asset return of 23.3% on market value which, in turn, caused a significant increase in the market related value of assets – assets used to determine NPPC as of January 1, 2004. The increase in the asset return component of NPPC and the decrease in the loss amortization component produced a negative NPPC for 2004. For the 2005 forecast, investment return in 2004 was assumed to be 0%, resulting in a decrease in the market related value of assets as of January 1, 2005. The resulting smaller asset return component and larger loss amortization component produced a positive NPPC forecasted for 2005.

CA-IR-337

Ref: T-15, page 9 & HECO-1504 (Pension Costs).

HECO-1504 provides NPPC amounts by year since 1995. Please provide the following:

a. Please update this schedule to reflect annual NPPC amounts for each year starting with the adoption of FAS87, including 2004 actual and any revised estimates for the 2005 test year forecast.

b. For each year (e.g., 1987-2005) referenced in item (a) above, please provide the following information since adoption of FAS87:

1. Discount rate.

2. Expected return on plan assets.

3. Actual return on plan assets.

4. Actual pension fund contribution.

c. Please explain and reconcile any variances between the cumulative NPPC provided in response to item (a) above and the prepaid pension asset balances set forth on HECO-1904.

HECO Response:

a. Updated HECO-1504 to reflect annual NPPC for each year since 1987, including 2004 actual and revised estimates for the 2005 test year is attached. The revised estimate for 2005 is based on a 6% discount rate. Actual NPPC for 2005 will be [illegible] response to CA-IR-98. At the time HECO-1904 was prepared, HECO was not expecting to make any contributions in 2004, however contributions were made as indicated in responses to CA-IR-98 and CA-IR-518.

Hawaiian Electric Company, Inc.
Pension & OPEB Costs
1987-2005

Line		(a) 1987 Actual	(b) 1988 Actual	(c) 1989 Actual	(d) 1990 Actual	(e) 1991 Actual	(f) 1992 Actual	(g) 1993 Actual	(h) 1994 Actual	(i) 1995 Actual	(j) 1996 Actual
1	Qualified Plan	9,216,777	8,307,882	9,007,061	9,739,662	10,617,695	11,382,007	10,939,516	10,924,690	6,408,000	8,380,584
2	Non-Qualified Plans	145,541	334,671	198,260	294,658	175,451	103,410	184,174	243,032	299,652	369,814
3	Total	9,362,318	8,642,553	9,205,321	10,034,320	10,793,146	11,485,417	11,123,690	11,167,722	6,707,652	8,750,398
4	OPEB - FAS 106	NA	NA	NA	NA	NA	NA	NA	NA	15,724,612	14,935,627
5	OPEB - Reg Asset Amort [1]									2,751,001	1,301,839
6	Total	NA	NA	NA	NA	NA	NA	NA	NA	18,475,613	16,237,466
7	OPEB - Executive Life Only	NA	NA	NA	NA	NA	NA	NA	NA	609,327	657,180
	Assumptions:										
	Discount Rate	7.50%	8.00%	8.50%	8.50%	8.50%	8.50%	8.50%	7.00%	8.00%	7.00%
	Asset Return Rate	7.50%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	9.00%	9.00%
	Medical Trend	NA	NA	NA	NA	NA	NA	NA	NA	7.50%	6.50%
	Dental Trend	NA	NA	NA	NA	NA	NA	NA	NA	6.00%	5.00%
	Vision Trend	NA	NA	NA	NA	NA	NA	NA	NA	5.00%	4.00%
	Actual Returns for Valuation	13.15%	0.58%	9.35%	0.78%	13.48%	23.51%	11.62%	11.27%	8.96%	11.27%
	Market Related Value Return	3.17%	4.34%	6.32%	3.42%	8.81%	12.06%	27.58%	10.49%	7.60%	13.06%
	Market Value Return	0.55%	6.89%	22.00%	-1.67%	25.93%	4.20%	16.16%	-2.77%	26.47%	13.92%
8	Contrib. To Pension Fund	8,736,278	8,307,882	9,007,061	9,739,662	10,617,695	11,382,007	10,939,516	10,924,690	9,058,124	6,971,824
9	Contrib. To OPEB Funding Vehicles	NA	NA	NA	NA	NA	NA	NA	NA	14,270,149	15,580,286

[1] Regulatory asset amortization began in January 1995

Hawaiian Electric Company, Inc.
Pension & OPEB Costs
1987-2005

Line		(k) 1997 Actual	(l) 1998 Actual	(m) 1999 Actual	(n) 2000 Actual	(o) 2001 Actual	(p) 2002 Actual	(q) 2003 Actual	(r) 2004 Actual	(s) 2005 Est.
1	Qualified Plan	7,117,179	1,870,595	(1,073,259)	(19,322,692)	(20,465,117)	(15,655,436)	5,894,495	(1,546,921)	4,416,000
2	Non-Qualified Plans	607,686	357,662	319,919	296,534	206,237	228,915	354,937	474,310	430,500
3	Total	7,724,865	2,228,257	(753,340)	(19,026,158)	(20,258,880)	(15,426,521)	6,249,432	(1,072,611)	4,846,500
4	OPEB - FAS 106	14,393,350	9,284,785	3,574,126	1,761,196	2,106,966	4,262,731	6,905,766	6,233,487	7,014,500
5	OPEB - Reg Asset Amort [1]	1,301,839	1,301,839	1,301,839	1,301,839	1,301,839	1,301,839	1,301,839	1,301,839	1,301,839
6	Total	15,695,189	10,586,624	4,875,965	3,063,035	3,408,805	5,564,570	8,207,605	7,535,326	8,316,339
7	OPEB - Executive Life Only	671,152	540,422	518,685	458,422	551,450	637,414	844,050	855,395	886,000
	Assumptions:									
	Discount Rate	7.00%	7.00%	6.50%	7.75%	7.50%	7.25%	6.75%	6.25%	6.00%
	Asset Return Rate	9.00%	10.00%	10.00%	10.00%	10.00%	10.00%	9.00%	9.00%	9.00%
	Medical Trend	6.50%	5.50%	5.00%	6.25%	6.00%	10%-4.75%	9.25%-4.25%	10%-4.25%	10%-4.25%
	Dental Trend	5.00%	4.00%	3.50%	4.75%	4.50%	4.75%	4.25%	4.25%	4.25%
	Vision Trend	4.00%	3.50%	3.00%	4.25%	4.00%	3.75%	3.25%	3.25%	3.25%
	Actual Returns for Valuation	13.49%	15.03%	25.19%	15.03%	13.45%	-14.69%	2.29%	8.67%	
	Market Related Value Return	14.09%	15.23%	28.31%	11.85%	5.04%	-14.52%	22.89%	2.58%	
	Market Value Return	15.23%	16.38%	30.10%	-3.32%	-10.26%	-13.90%	23.30%	10.13%	
8	Contrib. To Pension Fund	5,876,355	2,206,034	0	0	0	0	13,394,248	15,186,494	0
9	Contrib. To OPEB Funding Vehicles	15,024,037	10,046,203	4,357,280	2,604,613	2,857,355	4,927,156	7,363,555	6,679,931	7,430,339

[1] Regulatory asset amortization began in January 1995

Prepaid Pension Asset

	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996
Beginning Prepaid Pension Asset	480,499	-	-	-	-	-	-	-	-	2,650,124
Accrual NPPC[1]	9,216,777	8,307,882	9,007,061	9,739,862	10,617,695	11,382,007	10,939,516	10,924,690	6,408,000	8,380,584
Contributions to Trust[2]	8,736,278	8,307,882	9,007,061	9,739,862	10,617,695	11,382,007	10,939,516	10,924,690	9,058,124	6,971,824
Ending Prepaid Pension Asset	-	-	-	-	-	-	-	-	2,650,124	1,241,364

	1997	1998	1999	2000	2001	2002	2003	2004	2005
Beginning Prepaid Pension Asset	1,241,364	540	335,979	1,409,238	20,731,930	41,197,047	56,852,483	64,352,236	81,085,651
Accrual NPPC[1]	7,117,179	1,870,595	(1,073,259)	(19,322,692)	(20,465,117)	(15,655,436)	5,894,495	(1,546,921)	4,416,000
Contributions to Trust[2]	5,876,355	2,206,034	-	-	-	-	13,394,248	15,186,494	-
Ending Prepaid Pension Asset	540	335,979	1,409,238	20,731,930	41,197,047	56,852,483	64,352,236	81,085,651	76,669,651

Notes:
[1] NPPC per HECO-1504 Updated, line 1
[2] Contributions to trust per HECO-1504 Updated, line 8

CA-IR-338

Ref: T-15, pages 4-5 & HECO-1503 (Pension Costs).

Please provide the following information:

a. Please provide a complete copy of the Watson Wyatt FAS87 actuarial study supporting the 2004 actual NPPC recorded by HECO and the 2005 test year NPPC projection set forth on HECO-1503. [Note: HECO-WP-1550 appears to be a pension "contribution" study.]

b. Referring to item (a) above, please confirm that the studies were based on January 1, 2003 employee demographic and assumptions. If this cannot be confirmed, please explain.

c. Please provide complete copy of the 2004 Watson Wyatt FAS87 actuarial study (valuation as of January 1, 2004), including any reforecast of the 2005 projection. If the study is not yet available, please indicate when the study is expected to be completed and provide the requested information immediately upon receipt.

HECO Response:

a. Watson Wyatt, the plan's actuary, provided the attached set of exhibits on pages 2 to 30 to this response to support the 2004 actual NPPC and the 2005 test year NPPC projection.

b. The calculations in the response to part a. above are based on employee demographics and assumptions as of January 1, 2004.

c. See response to part a. above. A reforecast of the 2005 projection, based on employee demographics and assumptions as of January 1, 2005, will be completed by June, 2005. The revised forecast will be provided to the Commission and the parties as soon as it is available.

Hawaiian Electric Industries, Inc.
1/1/2004 NPPC
Amortization of (Gain)/Loss Allocated by (Gain)/Loss (same as done in projection of nppc)
(Gain)/Loss Amortized over average future amortization service

Discount Rate: 6.25%
LT Asset Return Rate: 9.00%

	Hecn	Helcn	Mecn	HEI	Total	Based on MV
Service Cost						
NRB	13,147,439	2,790,914	3,029,343	630,890	19,598,586	
Vesting	123,602	24,835	28,119	4,811	181,367	
Pre-Ret Death	373,718	78,919	91,732	11,340	555,709	
Total	13,644,759	2,894,668	3,149,194	647,041	20,335,662	
Projected Benefit Obligation						
NRB	237,091,897	50,952,121	49,335,769	11,275,721	348,655,508	
Vesting	1,424,604	245,183	263,937	54,667	1,988,391	
Pre-Ret Death	6,304,822	1,368,915	1,406,009	174,243	9,253,989	
Retirees	300,347,796	52,919,491	39,410,458	3,449,022	396,126,767	
Vested Terms	5,822,049	1,272,165	1,173,818	200,241	8,468,273	
Total	550,991,168	106,757,875	91,589,991	15,153,894	764,492,928	
Gain/Loss Calc						
1. PBO	550,991,168	106,757,875	91,589,991	15,153,894	764,492,928	764,492,928
2. MRV Assets	563,856,236	107,578,756	89,498,063	13,809,628	774,742,683	673,689,289
3. MV Assets	490,309,770	93,546,744	77,824,403	12,008,372	673,689,289	
4. Unrecognized Trans	0	0	0	0	0	0
5. Unrecog. Prior Svc						
a. Prior SC Prior to 1/1/2001	(4,940,843)	(1,267,023)	(1,037,352)	(180,948)	(7,426,166)	
b. Prior SC 1/1/2001-EGTRRA Limits	345,675	97,916	742	54,787	499,120	
c. Prior Service Cost @ 1/1/2004	(4,595,168)	(1,169,107)	(1,036,610)	(126,161)	(6,927,046)	(6,927,046)
6. (Accrued)/Prepaid	64,351,698	11,097,705	5,612,755	393,467	81,455,625	81,455,625
7. (Gain)/Loss based on MRV:(1)-(2)-(4)-(5)+(6)	56,081,798	11,445,931	8,741,293	1,863,894	78,132,916	179,186,310
8. (Gain)/Loss based on MV:(1)-(3)-(4)-(5)+(6)	129,628,264	25,477,943	20,414,953	3,665,150	179,186,310	
9. Adj. (Gain)/Loss for amortization: MV method						
a. Adjustment: (3) - (2)	(73,546,466)	(14,032,012)	(11,673,660)	(1,801,256)	(101,053,394)	(101,053,394)
b. Adjusted (Gain)/Loss: (8)+(9a)	56,081,798	11,445,931	8,741,293	1,863,894	78,132,916	78,132,916
10. Max(PBO,MRV)					774,742,683	764,492,928
11. 10% of (10): .10 X (10)					77,474,268	76,449,293
12. (Gain)/Loss Amort: (Abs(9b) or Abs(7)) - (11)					658,648	1,683,623
13. Average Future Amort. Svc.						
a. 1/1/2003 regular valuation grand total avg. future amort. svc.					13.51	13.51
14. Amortization					48,753	124,621
15. Allocated Amort. (by item (7))	34,994	7,142	5,454	1,163	48,753	

Net Periodic Pension Cost

	Hecn	Helcn	Mecn	HEI	Total
1. Service Cost					
a. Service Cost	13,644,759	2,894,668	3,149,194	647,041	20,335,662
b. Admin Expenses	278,000	51,000	45,000	6,000	380,000
c. Interest on a.	852,797	180,917	196,825	40,440	1,270,979
d. Total Service Cost	14,775,556	3,126,585	3,391,019	693,481	21,986,641
2. Interest cost					
a. PBO	550,991,168	106,757,875	91,589,991	15,153,894	764,492,928
b. Exp. Dist.:					
i. Current retirees	28,698,007	4,968,521	3,750,721	291,744	37,708,993
ii. Actives	1,774,214	269,454	227,283	248,359	2,519,310
iii. Total	30,472,221	5,237,975	3,978,004	540,103	40,228,303
b. Weighted 1/2	15,236,111	2,618,988	1,989,002	270,052	20,114,153
c. Average PBO	535,755,057	104,138,887	89,600,989	14,883,842	744,378,775
d. Discount Rate	6.25%	6.25%	6.25%	6.25%	6.25%
e. Interest Cost	33,484,691	6,508,680	5,600,061	930,240	46,523,672
3. Expected Return					
a. MRV Assets	563,856,236	107,578,756	89,498,063	13,809,628	774,742,683
b. Weighted Distrib.	15,236,111	2,618,988	1,989,002	270,052	20,114,153
c. Exp contrib	0	0	0	0	0
d. Weighted-see w/s wgtcontr-for 2004	0	0	0	0	0
e. Wgt Admin Exp - 1/2	139,000	25,500	22,500	3,000	190,000
f. Average Assets	548,481,125	104,934,268	87,486,561	13,536,576	754,438,530
g. Long-term Rate	9.00%	9.00%	9.00%	9.00%	9.00%
h. Expected Return	49,363,302	9,444,085	7,873,790	1,218,292	67,899,469
4. Trans Oblig. Amort.	0	0	0	0	0
5. Prior Svc. Cost Amort.					
a. Prior SC Amort. Prior to 1/1/2001	(509,103)	(130,553)	(106,889)	(18,645)	(765,190)
b. Prior SC 1/1/2001-EGTRRA Limits	30,243	8,566	65	4,793	43,667
c. Prior Service Cost @ 1/1/2004	(478,860)	(121,987)	(106,824)	(13,852)	(721,523)
6. (Gain)/Loss Amort.	34,994	7,142	5,454	1,163	48,753
7. NPPC	(1,546,921)	76,335	1,015,920	392,740	(61,926)

Retirement Plan for Employees of Hawaiian Electric Industries, Inc. and Participating Subsidiaries

Market Related Value for FAS87 as of 1/1/2004

Gain or Loss 2002

	Actual	Weighted	
(1) Market Value on 12/31/2001	687,757,720		
(2) Contributions	0	0	wgt calculated
(3) Benefit Payments	(33,467,894)	(16,733,947)	0.5000
(4) Admin Expenses	(752,103)	(376,052)	0.5000
(5) Expected Income at 10.0%	67,064,772		
(6) Expected Asset Value	720,602,495		
(7) Market Value on 12/31/2002	560,257,888		
(8) Gain/(Loss) for Year	(160,344,607)		
Actual Return:	(93,279,835)	-13.91% New	
	(94,031,938)	-14.01% Old	

Gain or Loss 2003

	Actual	Weighted	
(1) Market Value on 12/31/2002	560,257,888		
(2) Contributions	22,651,446	3,132,267	wgt calculated
(3) Benefit Payments	(35,994,987)	(17,997,494)	0.5000
(4) Admin Expenses	(351,927)	(175,964)	0.5000
(5) Expected Income at 9.0%	49,069,503		
(6) Expected Asset Value	595,631,923		
(7) Market Value on 12/31/2003	673,689,289		
(8) Gain/(Loss) for Year	78,057,366		
Actual Return:	127,126,869	23.32% New	
	126,774,942	23.24% Old	

Unrecognized Portion of Gains and Losses

December 31	Gain/(Loss)	Recognized	Unrecognized	Gain/(Loss)	
1999	134,919,802	100%	0%	0	38,140,638
2000	(112,434,917)	75%	25%	(28,108,729)	134,919,802
2001	(158,942,698)	50%	50%	(79,471,349)	-112434917
2002	(160,344,607)	25%	75%	(120,258,455)	-158942698
2003	78,057,366	0%	100%	78,057,366	-44679943
	Unrecognized Gain/(Loss):			(149,781,167)	

Adjusted Assets

	HECO	HELCO	MECO	HEI	TOTAL
(1) Market Value on December 31, 2003	$490,309,770	$93,546,744	$77,824,403	$12,008,372	$673,689,289
(2) Unrecognized Gain/(Loss)	(109,010,446)	(20,798,224)	(17,302,680)	(2,669,817)	(149,781,167)
(3) Market Related Value (1)-(2)	599,320,216	114,344,968	95,127,083	14,678,189	823,470,456
(4) 85% of Mkt Value	416,763,305	79,514,732	66,150,743	10,207,116	572,635,896
(5) 115% of Mkt Value	563,856,236	107,578,756	89,498,063	13,809,628	774,742,683
(6) Adjusted MRV (4) < [(3)] < (5)	563,856,236	107,578,756	89,498,063	13,809,628	774,742,683

Hawaiian Electric Industries, Inc.
1/1/2005 NPPC as of 1/1/2004
No Change in Assumptions from 1/1/2004

Discount Rate: 6.25%
LT Asset Return Rate: 9.00%

Estimate	Heco	Helco	Meco	HEI	Total	
	13,688,980	2,813,282	3,183,166	639,320	20,324,748	
	568,433,961	111,100,114	96,554,476	16,229,110	792,317,661	
Service Cost	14,230,890	2,924,652	3,309,179	664,629	21,129,350	21,129,350
Projected Benefit Obligation	568,962,295	111,203,377	96,644,219	16,244,194	793,054,085	793,054,085
Gain/Loss Calc						Based on MV
1. PBO	568,962,295	111,203,377	96,644,219	16,244,194	793,054,085	793,054,085
2. MRV Assets	546,854,153	104,992,370	87,775,340	13,628,738	753,250,601	691,885,648
3. MV Assets	502,303,668	96,438,972	80,624,560	12,518,448	691,885,648	
4. Unrecognized Trans	0	0	0	0	0	0
5. Unrecog. Prior Svc						
a. Prior SC Prior to 1/1/2001	(4,431,740)	(1,136,470)	(930,463)	(162,303)	(6,660,976)	
b. Prior SC 1/1/2001-EGTRRA Limits	315,432	89,350	677	49,994	455,453	
c. Prior Service Cost @ 1/1/2004	(4,116,308)	(1,047,120)	(929,786)	(112,309)	(6,205,523)	(6,205,523)
6. (Accrued)/Prepaid	65,898,619	11,021,370	4,596,835	727	81,517,551	81,517,551
7. (Gain)/Loss based on MRV:(1)-(2)-(4)-(5)+(6)	92,123,069	18,279,497	14,395,500	2,728,492	127,526,558	188,891,511
8. (Gain)/Loss based on MV:(1)-(3)-(4)-(5)+(6)	136,673,554	26,832,895	21,546,280	3,838,782	188,891,511	
9. Adj. (Gain)/Loss for amortization: MV method						
a. Adjustment: (3) - (2)	(44,550,485)	(8,553,398)	(7,150,780)	(1,110,290)	(61,364,953)	
b. Adjusted (Gain)/Loss: (8)+(9a)	92,123,069	18,279,497	14,395,500	2,728,492	127,526,558	
10. Max(PBO,MRV)					793,054,085	793,054,085
11. 10% of (10): .10 X (10)					79,305,409	79,305,409
12. (Gain)/Loss Amort: (Abs(9b) or Abs(7)) - (11)					48,221,149	48,221,149
13. Average Future Amort. Svc.						
a. 1/1/2003 regular valuation grand total avg. future amort. svc.					13.19	13.19
14. Amortization					3,655,887	3,655,887
15. Allocated Amort. (by item (7))	2,640,952	524,030	412,685	78,219	3,655,886	4,670,820
Net Periodic Pension Cost						
1. Service Cost						
a. Service Cost	14,230,890	2,924,652	3,309,179	664,629	21,129,350	
b. Admin Expenses	278,000	51,000	45,000	6,000	380,000	
c. Interest on a.	889,431	182,791	206,824	41,539	1,320,585	
d. Total Service Cost	15,398,321	3,158,443	3,561,003	712,168	22,829,935	
2. Interest cost						
a. PBO	568,962,295	111,203,377	96,644,219	16,244,194	793,054,085	
b. Exp. Dist.:	31,481,107	5,491,119	4,178,912	582,380	41,733,518	
c. Weighted 1/2	15,740,554	2,745,560	2,089,456	291,190	20,866,760	
d. Average PBO	553,221,741	108,457,817	94,554,763	15,953,004	772,187,325	
e. Discount Rate	6.25%	6.25%	6.25%	6.25%	6.25%	
f. Interest Cost	34,576,359	6,778,614	5,909,673	997,063	48,261,709	
3. Expected Return						
a. MRV Assets	546,854,153	104,992,370	87,775,340	13,628,738	753,250,601	
b. Weighted distrib.	15,740,554	2,745,560	2,089,456	291,190	20,866,760	
c. Exp contrib	0	0	0	0	0	
d. Weighted 1/2	0	0	0	0	0	
e. Wgt Admin Exp - 1/2	139,000	25,500	22,500	3,000	190,000	
f. Average Assets: (3a)-(3b)+(3d)-(3e)	530,974,599	102,221,310	85,663,384	13,334,548	732,193,841	
g. Long-term Rate	9.00%	9.00%	9.00%	9.00%	9.00%	
h. Expected Return: (3f)x(3g)	47,787,714	9,199,918	7,709,705	1,200,109	65,897,446	
4. Trans Oblig. Amort.	0	0	0	0	0	
5. Prior Svc. Cost Amort.						
a. Prior SC Amort. Prior to 1/1/2001	(509,103)	(130,553)	(106,889)	(18,645)	(765,190)	
b. Prior SC 1/1/2001-EGTRRA Limits	30,243	8,566	65	4,793	43,667	
c. Prior Service Cost @ 1/1/2005	(478,860)	(121,987)	(106,824)	(13,852)	(721,523)	
6. (Gain)/Loss Amort.	2,640,952	524,030	412,685	78,219	3,655,886	
7. NPPC	4,349,058	1,139,182	2,066,832	573,489	8,128,561	

**Retirement Plan for Employees of Hawaiian Electric Industries, Inc.
and Participating Subsidiaries**

Estimated Market Related Value for FAS87 as of 1/1/2005 (from 1/1/2004)

Estimated Gain or Loss 2003

	Actual	Weighted	
(1) Market Value on 12/31/2002	560,257,888		
(2) Contributions	22,651,446	3,132,267	wgt calculated
(3) Benefit Payments	(35,994,987)	(17,997,494)	0.5000
(4) Admin Expenses	(351,927)	(175,964)	0.5000
(5) Expected Income at 9.0%	49,069,503		
(6) Expected Asset Value	595,631,923		
(7)Market Value on 12/31/2003	673,689,289		
(8) Gain/(Loss) for Year	78,057,366		
Actual Return:	127,126,869	23.32% New	
	126,774,942	23.24% Old	

Estimated Gain or Loss 2004

	Actual	Weighted	
(1) Market Value on 12/31/2003	673,689,289		
(2) Contributions	0	0	wgt calculated
(3) Benefit Payments	(40,228,303)	(20,114,152)	0.5000
(4) Admin Expenses	(380,000)	(190,000)	0.5000
(5) Expected Income at 9.0%	58,804,662		
(6) Expected Asset Value	691,885,647		
(7) Est. Market Value on 12/31/2004	691,885,648		
(8) Gain/(Loss) for Year	1		
Actual Return:	58,804,663	9.00% New	
	58,424,663	8.94% Old	

Unrecognized Portion of Gains and Losses

December 31	Gain/(Loss)	Recognized	Unrecognized	Gain/(Loss)
2000	(112,434,917)	100%	0%	0
2001	(158,942,698)	75%	25%	(39,735,675)
2002	(160,344,607)	50%	50%	(80,172,304)
2003	78,057,366	25%	75%	58,543,025
2004	1	0%	100%	1
	Unrecognized Gain/(Loss):			(61,364,953)

Adjusted Assets

	HECO	HELCO	MECO	HEI	TOTAL
(1) Est. Market Value on December 31, 2004	$502,303,668	$96,438,972	$80,624,560	$12,518,448	$691,885,648
(2) Est. Unrecognized Gain/(Loss)	(44,550,485)	(8,553,398)	(7,150,780)	(1,110,290)	(61,364,953)
(3) Est. Market Related Value (1)-(2)	546,854,153	104,992,370	87,775,340	13,628,738	753,250,601
(4) 85% of Mkt Value	426,958,118	81,973,126	68,530,876	10,640,681	588,102,801

A. Source and Testing of Data

Active Participants

Hawaiian Electric Company, Inc. supplied computer files containing information on all active plan participants. The data included names, sex codes, dates of birth and hire, and monthly rates of base pay on January 1, 2004.

Inactive Participants

Hawaiian Electric Company, Inc. supplied computer files containing information on all inactive plan participants. The data for vested terminated former employees included names, sex codes, dates of birth and termination, and monthly accrued benefits. The data for retirees included names, sex codes, dates of birth, retirement dates, status changes, original monthly payment amounts, and COLA amounts.

Review Process

The data was checked for internal consistency and was accepted as reasonable by the actuary. All employees who were participants in the plan on the valuation date were included in the valuation.

B. Comparison with Prior Year

	Valuation Date 1/1/2003	Valuation Date 1/1/2004
Basic Data		
(1) Number of Covered Employees		
(a) Active Employees	1,938	1,891
(b) Retirees	1,372	1,256[1]
(c) Survivors	Included in (b)	147
(d) QDRO Alternate Payess	Included in (b)	30
(e) Prudential Retirees	Included in (b)	10
(f) Vested Former Employees	245	274
(g) Transferred Employees	6	5
(h) Disabled Employees on LTD	16	11
(2) Approximate Covered Annual Payroll	$123,191,365	$124,403,643
(3) Total Annual Benefits of Inactive Participants		
(a) Retirees and Survivors[1]	34,715,005	41,695,345
(b) Vested Former Employees	2,010,648	2,273,909
(c) Transferred Employees	163,897	155,541
(d) Disabled	266,402	190,685
Participant Averages		
(4) Averages for Active Employees		
(a) Years of Past Service	14.95	14.80
(b) Attained Age	45.24	45.53
(c) Retirement Age	59.16	59.23
(d) Covered Annual Pay	63,566	65,787
(e) Accrued Annual Benefit	17,521	17,950
(f) Projected Annual Benefit at Age 65	93,299	95,113
(5) Retiree Averages[2]		
(a) Retirement Age	58.20	58.09
(b) Attained Age	68.07	68.20
(c) Annual Benefit	27,844	31,763
Vested Status		
(6) Vested Status of Active Employees		
(a) Number Fully Vested	1,636	1,559
(b) Number Partially Vested	0	0
(c) Number Not Vested	302	332
(d) Total	1,938	1,891

[1] Excluding Prudential retirees.
[2] Excluding survivors, alternate payees, and Prudential retirees.

C. Basic Data by Participating Company

Basic Data	HECO	HELCO	MECO	HEI	Total
(1) Number of Covered Employees					
(a) Active Employees	1,273	283	291	44	1,891
(b) Retirees[1]	940	166	141	9	1,256
(c) Survivors	116	15	15	1	147
(d) QDRO Alternate Payees	24	6	0	0	30
(e) Prudential Retirees	10	0	0	0	10
(f) Vested Former Employees	195	33	39	7	274
(g) Transferred Employees	2	0	0	3	5
(h) Disabled on LTD	8	1	2	0	11
(2) Approximate Covered Annual Payroll for Active Participants on Valuation Date	$84,026,264	$17,385,410	$18,463,133	$4,528,836	$124,403,643
(3) Annual Benefits of Inactive Participants					
(a) Retirees and Survivors[1]	31,804,276	5,351,567	4,224,229	315,273	41,695,345
(b) Vested Former Employees	1,561,324	317,631	354,826	40,128	2,273,909
(c) Transferred Employees	40,214	0	0	115,327	155,541
(d) Disabled	123,983	19,427	47,275	0	190,685

[1] Excluding Prudential retirees.

	HECO	HELCO	MECO	HEI	Total
Employee Averages					
(4) Averages for Active Employees					
(a) Years of Past Service	14.99	15.14	14.04	12.26	14.80
(b) Attained Age	45.54	45.80	44.94	47.55	45.53
(c) Retirement Age	59.27	59.11	59.06	59.77	59.23
(d) Covered Annual Pay	$66,006	$61,433	$63,447	$102,928	$65,787
(e) Accrued Annual Benefit	18,221	17,495	16,597	21,998	17,950
(f) Annual Benefit at Age 65	96,153	89,465	94,923	102,624	95,113
(g) Annual Benefit at Age 65 without Maximum Limit	96,153	89,465	94,923	102,624	95,113
(5) Retiree Averages[1]					
(a) Retirement Age	58.13	57.76	58.18	58.98	58.09
(b) Attained Age	68.61	65.67	[redacted]	[redacted]	[redacted]

[redacted]

Vested Status

	HECO	HELCO	MECO	HEI	Total
(6) Vested Status of Employees as of 1/1/2004					
(a) Number Fully Vested	1,065	229	227	38	1,559
(b) Number Not Vested	208	54	64	6	332
(c) Total	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

[redacted]

D. Benefit Projections

Set forth below is an exhibit showing for active employees within each employer group the projected amounts of annual benefits commencing at normal retirement age during each of the next five years. These projections are estimates, taking into account the assumed pay increases, and further assume that these participants will remain in service until normal retirement date.

	Year	Number Attaining Age 65	Annual Benefits First Commencing in Year
HECO			
	2004	14	475,958
	2005	8	367,289
	2006	8	306,356
	2007	8	342,155
	2008	25	1,117,691
HELCO			
	2004	1	8,814
	2005	0	0
	2006	1	25,977
	2007	1	20,520
	2008	3	122,942
MECO			
	2004	0	0
	2005	0	0
	2006	1	38,818
	2007	2	79,056
	2008	4	137,566
HEI			
	2004	4	303,341
	2005	0	0
	2006	0	0
	2007	1	104,907
	2008	0	0

E. Distribution of Active Employees by Age and Service

This section shows a distribution of active employees in five-year age and service groups. Counts are shown separately for male and female employees.

HECO

Age Last Birthday		Completed Years of Past Vesting Service							Total
		0-4	5-9	10-14	15-19	20-24	25-29	30& Over	
Under 20	M								0
	F								0
20-24	M	1							1
	F	2							2
25-29	M	12	1						13
	F	5	1						6
30-34	M	41	22	28	1				92
	F	9	9	10					28
35-39	M	31	20	90	24				165
	F	13	15	23	8				59
40-44	M	22	15	77	68	9			191
	F	11	9	37	19	3			79
45-49	M	15	12	43	47	23	14	5	159
	F	10	5	20	20	10	2	2	69
50-54	M	11	5	29	27	11	17	43	143
	F	8	3	13	16	9	7	10	66
55-59	M	8	4	11	17	3	7	54	104
	F	2	1	7	7	5	2	9	33
60-64	M	6	3	3	11		2	17	42
	F	1	1	3	3	1	1	1	11
65&over	M				1			6	7
	F		1			1		1	3
Total	M	147	82	281	196	46	40	125	917
	F	61	45	113	73	29	12	23	356

HELCO

Age Last Birthday		Completed Years of Past Vesting Service							Total
		0-4	5-9	10-14	15-19	20-24	25-29	30& Over	
Under 20	M								0
	F								0
20-24	M	1							1
	F								0
25-29	M	4							4
	F	3							3
30-34	M	7	4	8					19
	F	4	4	1					9
35-39	M	6	7	13	2				28
	F	4	3	5					12
40-44	M	9	3	13	10	2			37
	F	1	3	3	2				9
45-49	M	4	5	6	7	4	4	2	32
	F	1	2	8	3	2	2		18
50-54	M	5		8	14	7	7	20	61
	F	1		3	3	3	2	6	18
55-59	M	4			4	3		13	24
	F				2				2
60-64	M		2					1	3
	F				1			1	2
65&over	M	1							1
	F								0
Total	M	41	21	48	37	16	11	36	210
	F	14	12	20	11	5	4	7	73

MECO

Age Last Birthday		Completed Years of Past Vesting Service							Total
		0-4	5-9	10-14	15-19	20-24	25-29	30& Over	
Under 20	M								0
	F								0
20-24	M								0
	F	1							1
25-29	M	4	1						5
	F	4							4
30-34	M	14	7	4					25
	F	3	2	1					6
35-39	M	11	7	21					39
	F	2	3	3					8
40-44	M	12	6	13	9	2			42
	F	3	1	3	2	1			10
45-49	M	4	5	10	8	15	4		46
	F	1	3	6	4		2		16
50-54	M	2	1	6	8	15	7	5	44
	F			1	3	3	3	2	12
55-59	M	2		4		5	2	6	19
	F				2	2	3		7
60-64	M	1	1		1	2		1	6
	F					1			1
65&over	M								0
	F								0
Total	M	50	28	58	26	39	13	12	226
	F	14	9	14	11	7	8	2	65

HEI

Age Last Birthday		Completed Years of Past Vesting Service							Total
		0-4	5-9	10-14	15-19	20-24	25-29	30& Over	
Under 20	M								0
	F								0
20-24	M								0
	F								0
25-29	M								0
	F	1							1
30-34	M								0
	F								0
35-39	M	2							2
	F	1	1	4					6
40-44	M			1					1
	F	1	1	5	3				10
45-49	M			3					3
	F		3	3	1				7
50-54	M			2		1			3
	F			1	1				2
55-59	M			1					1
	F	1		1	1				3
60-64	M			1	2				3
	F								0
65&over	M							1	1
	F				1				1
Total	M	2	0	8	2	1	0	1	14
	F	4	5	14	7	0	0	0	30

F. Reconciliation of Participants

HECO

	Active Employees	Retirees	Vested Term	Transfers Out of Plan	LTD
(1) Participants on 1/1/2003	1,308	1,052	180	2	7
(2) Withdrawals					
(a) Non-Vested Term.	(10)	0	0	0	0
(b) Vested Term.	(22)	0	22	0	0
(c) Cash Outs	0	0	0	0	0
(d) Transfers Within Plan	(3)	(1)	0	0	0
(e) Retirements – Regular	(41)	48	(6)	0	(1)
(f) Retirements – QDRO	0	0	0	0	0
(g) Deaths - No Benefits	0	(11)	0	0	0
(h) Deaths - Survivor Benefits	0	(4)	0	0	(1)
(i) LTD	(2)	0	(1)	0	3
(j) Transfer Out of Plan	0	0	0	0	0
(k) Survivors	0	5	0	0	0
(l) QDRO Alternate Payees	0	0	0	0	0
(m) Data Adjustments	0	1	0	0	0
(n) Totals	(78)	38	15	0	1
(3) Entrants					
(a) New Entrants	41	0	0	0	0
(b) Transfers Within Plan	1	0	0	0	0
(c) Rehires/Returns	1	0	0	0	0
(d) Totals	43	0	0	0	0
(4) Participants on 1/1/2004	1,273	1,090	195	2	8

HELCO

	Active Employees	Retirees	Vested Term	Transfers Out of Plan	LTD
(1) Participants on 1/1/2003	284	168	27	1	2
(2) Withdrawals					
(a) Non-Vested Term.	0	0	0	0	0
(b) Vested Term.	(6)	0	8	0	(2)
(c) Cash Outs	0	0	0	0	0
(d) Transfers Within Plan	0	0	0	(1)	0
(e) Retirements	(18)	19	(1)	0	0
(f) Deaths - No Benefits	0	(2)	0	0	0
(g) Deaths - Survivor Benefits	(1)	0	0	0	0
(h) LTD	(1)	0	0	0	1
(i) Transfer Out of Plan	0	0	0	0	0
(j) Survivors	0	1	0	0	0
(k) QDRO Alternate Payees	0	0	0	0	0
(l) Data Adjustments	0	0	0	0	0
(m) Totals	(26)	18	7	(1)	(1)
(3) Entrants					
(a) New Entrants	20	0	0	0	0
(b) Transfers Within Plan	4	1	0	0	0
(c) Rehires/Returns	1	0	(1)	0	0
(d) Totals	25	1	(1)	0	0
(4) Participants on 1/1/2004	283	187	33	0	1

MECO

	Active Employees	Retirees	Vested Term	Transfers Out of Plan	LTD
(1) Participants on 1/1/2003	301	142	31	0	7
(2) Withdrawals					
(a) Non-Vested Term.	(3)	0	0	0	0
(b) Vested Term.	(4)	0	9	0	(5)
(c) Cash Outs	0	0	0	0	0
(d) Transfers Within Plan	(2)	0	0	0	0
(e) Retirements	(16)	17	(1)	0	0
(f) Deaths - No Benefits	0	(3)	0	0	0
(g) Deaths - Survivor Benefits	0	0	0	0	0
(h) LTD	0	0	0	0	0
(i) Transfer Out of Plan	0	0	0	0	0
(j) Survivors	0	0	0	0	0
(k) QDRO Alternate Payees	0	0	0	0	0
(l) Data Adjustments	0	0	0	0	0
(m) Totals	(25)	14	8	0	(5)
(3) Entrants					
(a) New Entrants	14	0	0	0	0
(b) Transfers Within Plan	1	0	0	0	0
(c) Rehires/Returns	0	0	0	0	0
(d) Totals	15	0	0	0	0
(4) Participants on 1/1/2004	291	156	39	0	2

HEI

	Active Employees	Retirees	Vested Term	Transfers Out of Plan	LTD
(1) Participants on 1/1/2003	45	10	7	3	0
(2) Withdrawals					
(a) Non-Vested Term.	(1)	0	0	0	0
(b) Vested Term.	0	0	0	0	0
(c) Cash Outs	0	0	0	0	0
(d) Transfers Within Plan	(1)	0	0	0	0
(e) Retirements	0	0	0	0	0
(f) Deaths - No Benefits	0	0	0	0	0
(g) Deaths - Survivor Benefits	0	0	0	0	0
(h) LTD	0	0	0	0	0
(i) Transfer Out of Plan	0	0	0	0	0
(j) Survivors	0	0	0	0	0
(k) QDRO Alternate Payees	0	0	0	0	0
(l) Data Adjustments	0	0	0	0	0
(m) Totals	(2)	0	0	0	0
(3) Entrants					
(a) New Entrants	1	0	0	0	0
(b) Transfers Within Plan	0	0	0	0	0
(c) Rehires/Returns	0	0	0	0	0
(d) Totals	1	0	0	0	0
(4) Participants on 1/1/2004	44	10	7	3	0

G. Distribution of Inactive Vested Participants

Retired Participants[1]

Age Distribution

Age Group	HECO		HELCO		MECO		HEI		Totals	
	M	F	M	F	M	F	M	F	M	F
Up to 40	0	0	0	0	0	1	0	0	0	1
40-44	0	1	0	0	0	0	0	0	0	1
45-49	0	3	0	4	0	0	0	0	0	7
50-54	14	13	4	0	9	0	0	0	27	13
55-59	101	49	44	12	17	4	0	1	162	66
60-64	193	48	34	7	26	6	2	3	255	64
65-69	146	44	21	4	17	4	0	0	184	52
70-74	139	35	16	7	21	7	1	1	177	50
75-79	107	45	14	5	16	6	1	0	138	56
80-84	71	27	7	2	9	7	0	1	87	37
85-89	21	17	5	0	1	3	0	0	27	20
90 & up	4	2	1	0	2	0	0	0	7	2
Totals	796	284	146	41	118	38	4	6	1064	369

Benefit Distribution

Age Group	HECO	HELCO	MECO	HEI	Totals
Up to 40	$ 0	$ 0	$ 12,461	$ 0	$ 12,461
40-44	30,256	0	0	0	30,256
45-49	15,980	26,157	0	0	42,137
50-54	557,251	60,554	212,757	0	830,562
55-59	5,072,007	1,834,065	706,174	46,872	7,659,118
60-64	8,534,550	1,372,034	1,116,343	177,256	11,200,183
65-69	5,828,321	802,380	616,485	0	7,247,186
70-74	5,311,443	521,421	742,471	61,563	6,636,898
75-79	4,011,001	470,436	555,298	2,031	5,038,766
80-84	2,046,850	208,316	217,562	27,551	2,500,279
85-89	357,193	52,339	23,534	0	433,066
90 & up	39,424	3,865	21,144	0	64,433
Totals	$ 31,804,276	$ 5,351,567	$ 4,224,229	$ 315,273	$ 41,695,345

[1] Excluding retirees for whom death benefits were not purchased from Prudential.

Terminated Vested Participants

Age Distribution

Age Group	HECO M	HECO F	HELCO M	HELCO F	MECO M	MECO F	HEI M	HEI F	Totals M	Totals F
Up to 40	12	17	3	0	0	2	0	0	15	19
40-44	27	11	3	4	9	2	0	1	39	18
45-49	40	8	4	2	10	1	0	0	54	11
50-54	21	6	10	3	8	3	2	2	41	14
55-59	24	11	2	0	4	0	1	0	31	11
60-64	11	5	0	1	0	0	0	1	11	7
65 & Over	2	0	1	0	0	0	0	0	3	0
Totals	137	58	23	10	31	8	3	4	194	80

Benefit Distribution

Age Group	HECO	HELCO	MECO	HEI	Totals
Up to 40	$ 204,886	$ 23,184	$ 12,805	$ 0	$ 240,875
40-44	328,752	41,648	120,128	3,801	494,329
45-49	470,558	63,580	97,029	0	631,167
50-54	224,188	135,247	97,801	26,082	483,318
55-59	209,680	30,417	27,063	5,527	272,687
60-64	116,992	22,482	0	4,718	144,192
65 & Over	6,268	1,073	0	0	7,341
Totals	$1,561,324	$317,631	$354,826	$40,128	$2,273,909

Transferred Employees

Age Distribution

Age Group	HECO M	HECO F	HELCO M	HELCO F	MECO M	MECO F	HEI M	HEI F	Totals M	Totals F
30-34	0	0	0	0	0	0	0	0	0	0
35-39	0	0	0	0	0	0	0	0	0	0
40-44	0	0	0	0	0	0	0	1	0	1
45-49	1	0	0	0	0	0	1	0	2	0
50-54	1	0	0	0	0	0	0	1	1	1
Totals	2	0	0	0	0	0	1	2	3	2

Benefit Distribution

Age Group	HECO	HELCO	MECO	HEI	Totals
30-34	$ 0	$ 0	$ 0	$ 0	$ 0
35-39	0	0	0	0	0
40-44	0	0	0	26,527	26,527
45-49	22,579	0	0	24,631	47,210
50-54	17,635	0	0	64,169	81,804
Totals	$40,214	$ 0	$ 0	$115,327	$155,541

A. History of Plan

The Retirement Plan for Employees of Hawaiian Electric Company, Inc., Not Represented by Collective Bargaining Agreements and the Retirement Plan for Employees of Hawaiian Electric Company, Inc., Represented by Collective Bargaining Agreements were adopted by Hawaiian Electric Company, Inc. effective January 1, 1941. Benefits under the plans were funded through Prudential Group Annuity Contract No. GA-199. Effective January 1, 1947, Hilo Electric Light Company, Ltd. established a retirement plan for its employees. Benefits under that plan were funded through Prudential Group Insurance Contract No. GA-219. Maui Electric Company, Ltd. adopted a retirement plan for its employees on August 1, 1954. Benefits under that plan were funded through John Hancock Group Annuity Contract No. 367 GAC.

Effective December 28, 1967, Maui Electric Company, Ltd. entered into an agreement with First Hawaiian Bank to administer the trust as part of the Maui Electric Company, Ltd. Pension Plan. As of December 1, 1971, the separate non-bargaining and bargaining unit retirement plans of Hawaiian Electric Company, Inc. were merged and coverage was extended to include employees of Hilo Electric Light Company, Inc. and Maui Electric Company, Inc. The name of the merged plan was amended effective July 1, 1983 and was thereafter called the Retirement Plan for Employees of Hawaiian Electric Industries, Inc. and Participating Subsidiaries.

The plan was restated effective January 1, 1989 to include, among other changes, a five-year vesting schedule. Molokai Electric Company, Ltd. Pension Plan was merged into the plan effective December 31, 1989.

The plan was again restated effective January 1, 1994 to reflect various prior amendments made to the plan and certain amendments required by changes in the laws regulating the plan.

The plan was amended effective January 1, 1999 to provide a partial lump sum optional form of distribution and to extend death benefits to single employees. A summary of the principal provisions of the plan is included in the next section.

B. Summary of Principal Plan Provisions

(1)	Effective Date	January 1, 1941. Latest amendment negotiated August 15, 1998. Latest amendment adopted March 14, 2003.
(2)	Eligibility:	Employees of Hawaiian Electric Industries, Inc. and the controlled group to which participation is extended shall participate upon commencement of employment (regular employment for union employees).
(3)	Compensation:	Base pay including salary reduction contributions to the 401(k) plan, Section 125 plan, and Section 132(f) plan, but not including overtime or premium pay, bonuses or contributions to any other plan. Compensation shall be limited to the level prescribed in Section 401(a)(17) of the Internal Revenue Code.
(4)	Final Average Compensation:	The average monthly full-time rate of Compensation paid to an employee during the 36-consecutive months of his last ten years of employment, which produce the highest such average. For part-time employees, monthly pays are multiplied by a "full-time equivalent" ratio.
(5)	Vesting Service:	The elapsed period of service from hire to termination. For participants who sever employment and are reemployed within a twelve-month period, Vesting Service will also include such period of severance.
(6)	Credited Service:	The elapsed period of service from participation to termination. Union employees receive Credited Service for the initial probationary period once they become participants. Active Participants that retire or die on or after age 55 will receive additional Credited Service for any sick leave not used in the last 3 years of Vesting Service, up to a maximum of 12 weeks for each such year of Vesting Service.

Participants incurring a long-term disability shall be granted Credited Service for the period of such disability prior to the commencement of the distribution of accrued benefits.

(7) Normal Retirement:

(a) Eligibility Date

First day of the month in which the participant attains age 65 if born on the 1st through 15th of the month. First day of the next following month if the participant was born after the 15th. The day following the last day of employment (after attaining age 65) with 30 days advance written notice from the participant.

(b) Monthly Benefit

(i) Participants represented by IBEW Unit 8

The lesser of (A) 1.83% times the participant's final rate of pay (converted to a monthly rate) times Credited Service or (B) 60% of such final rate of pay.

(ii) Participants not represented by IBEW Unit 8

The lesser of (A) 2.04% times Final Average Compensation times Credited Service or (B) 67% of Final Average Compensation.

(8) Early Retirement:

(a) Eligibility Date

First day of the month not more than 10 years prior to a participant's normal retirement date with at least 5 years of Vesting Service or after attainment of age 50 with at least 5 years of Vesting Service and 65 points (i.e., age plus Vesting Service is at least 65).

(b) Monthly Benefit

The benefit calculated as in (7)(b) above, reduced to reflect earlier commencement in accordance with the following schedule (interpolated to the nearest month):

Age	Percentage Payable
60+	100%
59	99
58	98
57	97
56	96
55	95
54	90
53	85
52	80
51	75
50	70

In determining the applicable percentage, a participant's actual age shall be increased by one full year for each full year of Vesting Service in excess of 33 years.

(9) Postponed Retirement:

If a participant remains in service after his normal retirement date, his retirement benefit will be calculated as of such late retirement date and shall begin on the first day of the month following his last day of employment. However, with 30 days advance written notice from the participant, benefits shall begin on the day following the last day of employment.

(10) Vesting:

If a participant terminates service prior to meeting the eligibility requirements for early retirement, he will receive a percentage of his normal retirement benefit, calculated as in (7)(b) above, depending on his Vesting Service in accordance with the following schedule:

Years of Vesting Service	Percentage
Less than 5	0 %
5 and over	100

Benefits may commence upon satisfaction of the Early Retirement eligibility requirements in (8)(a) above. Benefits commencing prior to normal retirement date shall be actuarially reduced.

(11) Death Benefit for Vested Participants:

(a) Eligibility

Death of a participant with vested benefits, with death occurring prior to the commencement of benefits.

(b) Monthly Benefit

The beneficiary will receive a lifetime pension commencing on the date the participant would have been first eligible to retire, equal to the amount to which the beneficiary would have been entitled had the participant (A) terminated employment on the day of death, (in the case of an employee who dies while actively employed), (B) survived to his earliest retirement age, (C) retired on such earliest retirement date with a 50% joint and survivor annuity, (D) and then died.

For single participants that die prior to earliest retirement age, the designated beneficiary will receive a lump sum payment.

(12) Adjustment to Retirement Income:

(i) For retirements or deaths following 10/31/1979 and prior to 11/1/1981

Pensions are increased by 2.5% of the amount payable to a retiree or a surviving spouse or contingent annuitant of a retiree or active participant, calculated as of the date of retirement, for each 2-year period following the participant's date of retirement.

(ii) For retirement or deaths on or after 11/1/1981

The same as (i) above except that the percentage shall be 3% instead of 2.5%.

(13) Form of Benefit:

(a) Normal	Reduced 50% joint and survivor annuity if married. Single life annuity if single.
(b) Optional	Full or partial lump sum payout option up to $50,000. 33-1/3%, 50%, 66-2/3% or 100% contingent annuitant options, single life annuity option and the social security adjustment option. Options are actuarially equivalent to a single-life annuity.

C. Actuarial Assumptions

The actuarial assumptions determine the value of benefits expected to be paid under the plan. The assumptions take into account probabilities for determining how many and at what time employees will become eligible for benefits, the size of the benefits expected to be paid under the plan, how long benefits will be paid, and the current value of future benefits.

The mortality assumption in item (1) below was changed from the 1971 Group Annuity Mortality Table for Males with a two year setback for males and an eight year setback for females. The lump sum option in item (10) below was changed from a 50% election rate for retiring participants to reflect lower historical election percent experience. Finally, the mortality assumption for valuing the lump sum option was changed from the 1983 Group Annuity Mortality Table (average male and female rates) to the 1994 Group Annuity Reserve Mortality Table projected to 2002 (average of male and female unloaded rates.) The other actuarial assumptions used in the current valuation are the same as those used last year. These assumptions are shown below:

(1) Mortality:	The 1983 Group Annuity Mortality Table male and female rates.
(2)(a) Discount Rate:	6.25%.
(2)(b) Long Term Asset Return Rate:	9.00%.
(3) Salary Increases:	The following schedule shows representative rates at selected ages.

Age	Rates
20	17.29%
25	13.17
30	10.24
35	8.15
40	6.67
45	5.61
50	4.86
55	4.32
60	3.94
65	3.67

(4) Withdrawal:

The following schedule shows representative rates at selected ages.

Age	Rates	
	Males	Females
20	7.4%	6.2%
25	4.9	3.7
30	3.4	2.5
35	2.4	1.7
40	1.3	1.2
45	0.7	0.7
50	0.0	0.3
55 and over	0.0	0.0

(5) Retirement Age:

The assumed rates of retirement are shown below:

Age	Rate
Below 50	0%
50	2
51	2
52	2
53	2
54	4
55	15
56	15
57	15
58	15
59	15
60	15
61	15
62	30
63	25
64	30
65	50
66	50
67	50
68 and over	100

(6) Maximum Benefits:

It is assumed that the maximum benefit and pay limits in effect during 2004 will increase by 3% per year.

(7) Pre-Retirement Death Benefit:

100% of participants are assumed to have beneficiaries of the opposite sex, with females three years younger than males.

(8) Expenses:

$380,000

(9)	Former Employees:	It is assumed that former employees who are not actively employed on the valuation date will not be rehired.
(10)	Lump Sum Option:	It is assumed that 20% of retiring participants will elect the maximum allowable lump sum payment.

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Ref: T-15, page 6 (Pension Contribution).

At lines 18-25, the referenced testimony generally describes the Company's pension funding practice, but observes that the actual contribution may differ from the $4,349,000 forecast, referring to HECO's comprehensive income situation discussed by Mr. Von Gnechten in HECO

T-21. Please provide the following:

a. Please provide a pinpoint citation to the portion of HECO T-21 referenced by this passage.

b. At what point in time would HECO determine whether to fund the $4,349,000 forecast? Please explain.

c. Referring to HECO-1503, the contribution range is $0 to about $46.8 million. If HECO were to conclude that the contribution amount should be less than the pension cost included in the 2005 test year forecast, please explain how HECO would propose that the unfunded pension cost be recognized in quantifying overall revenue requirement (i.e., operating expense and rate base).

HECO Response:

a. See HECO T-21, page 38-39.

b. HECO's NPPC for 2005 is currently estimated to be $4,416,000 at a 6% discount rate. The current forecast does not anticipate any contributions in 2005 due to a $5.5 million contribution made on December 31, 2004, to sufficiently fund any anticipated shortfall in plan assets at December 31, 2004. However, funding determination will be reviewed in the fourth quarter of 2005 after evaluating the anticipated funded status at December 31, 2005, based on the asset value and the status of interest rates at that time. In 2004, HECO contributed $15.2 million to the pension plan.

c. If the amount contributed to the fund is less than the pension cost included in the 2005 test year estimate, the Prepaid Pension asset balance will decrease, which will result in a lower amount being included in rate base. The NPPC is the amount included in the 2005 test year estimate as operating expense.